APPENDIX AA
CASE-BY-CASE MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY APPLICATION

Transmittal Via MARAD License Application Docket

Mr. Jeff Robinson
Chief, Air Permits Section
U.S. EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

Re: Deepwater Port License Application
Case-by-case MACT Determination Request
Bluewater Texas Terminal LLC ("BWTT")

May 31, 2019

Dear Mr. Robinson:

Pursuant to 33 CFR § 148.700(b), BWTT is required to prepare and submit applications to each respective agency that requires a permit or license to operate a deepwater port. Permits required under the Clean Air Act include a Case-by-case Maximum Achievable Control Technology ("MACT") Determination, a Prevention of Significant Deterioration ("PSD") Permit, and a Title V Operating Permit. Applications for all required Clean Air Act permits have been included in BWTT's Deepwater Port License application.

This letter transmits BWTT's request for a Case-by-case MACT Determination.

I certify that, based on information and belief formed after reasonable inquiry, that the statements and information contained in these documents are true, accurate and complete.

If you have any questions regarding this application, please contact Dr. Chintan Mehta of Phillips 66 Company at Chintan.Mehta@p66.com or 832-765-1677; or Dr. Jesse Lovegren of DiSorbo Consulting, LLC, at jlovegren@disorboconsult.com or 512-961-4471.

Yours,

DFarris

David Farris
Vice President
BWTT

Enclosure

Application for Case-by-Case MACT Determination

Bluewater Texas Terminal LLC
Bluewater SPM Project
Gulf of Mexico

MAY 2019

DiSorbo
Environmental Consulting Firm

8501 North Mopac Expy | Suite 300 | Austin, TX 78759
512.693.4190 (P) | 512.279.3118 (F) | www.disorboconsult.com

Table of Contents

Table of Contents (Continued)

List of Tables

List of Figures

Table of Contents (Continued)

Appendices

Section 1
Application Context

Bluewater Texas Terminal LLC ("BWTT"), an affiliate of Phillips 66 Company, proposes to construct a deepwater port for export of crude oil in the United States Gulf of Mexico, approximately 18 statute miles offshore of Port Aransas, Texas.

The Deepwater Port Act ("DWPA", 33 USC § 1501 et seq.) requires that a person wishing to construct, own or operate a deepwater port obtain a license from the Secretary of Transportation. The proposed deepwater port will consist of two single point mooring (SPM) systems, subsea pipelines for transporting crude oil from shoreside storage points, and other equipment. The terminal meets the definition of a "deepwater port" (33 USC § 1502(9)) and is subject to the licensing requirements of the DWPA. BWTT must obtain a license from the U.S. Department of Transportation Maritime Administration (MARAD) before construction on the terminal may begin.

MARAD regulations implementing the DWPA require an analysis showing that the deepwater port will comply with all applicable Federal, Tribal, and State requirements for the protection of the environment (33 CFR § 148.105(z)), and also require that an applicant prepare and submit applications to the Environmental Protection Agency (EPA) for all permits required under the Clean Air Act (33 CFR § 148.700). EPA is a cooperating agency under the DWPA licensing program (33 CFR § 148.3(d)).

The following Clean Air Act requirements potentially apply to DWPA license applicants.

- Section 111 of the Clean Air Act requires EPA to promulgate performance standards ("NSPS") applying to each "new source" within specified source categories. EPA has not to date promulgated any NSPS applying to deepwater ports.
- Section 112 of the Clean Air Act requires EPA to promulgate National Emissions Standards for Hazardous Air Pollutants (NESHAP). Major sources of HAP must apply the Maximum Achievable Control Technology (MACT) for each applicable NESHAP. Additionally, each "new source" which is a major source of HAP must apply MACT, regardless of whether an applicable NESHAP has been promulgated.
- Clean Air Act New Source Review (NSR) requirements apply to the construction of a "major emitting facility" or a "major stationary source." Nonattainment NSR permitting applies to

construction in areas designated nonattainment for any pollutant for which a National Ambient Air Quality Standard (NAAQS) has been promulgated, while Prevention of Significant Deterioration (PSD) permitting applies to construction in areas designated attainment for at least one NAAQS pollutant. In the DWPA licensing context, additional preconstruction review that apply in the nearest coastal state (“minor NSR”) may be imposed by EPA to the extent these are required under DWPA (33 USC § 1518(b)).

- Major sources (for purposes of either NESHAP or NSR) are subject to Clean Air Act Operating Permit (“Title V”) requirements.

The proposed terminal will be a major source for purposes of the NESHAP, Title V and NSR programs. In order to meet the requirements of 33 CFR § 148.700, BWTT is submitting applications for all applicable Clean Air Act Permits, including:

1. An application for a case-by-case MACT determination;
2. A Title V permit application; and
3. A Prevention of Significant Deterioration (PSD) permit application, which additionally contains information relevant to the Texas minor NSR program.

The present application is for a case-by-case MACT determination.

Section 2
Introduction

2.1 Applicant Information

Applicant Name:

Blue Water Texas Terminal LLC

Applicant Mailing Address:

2331 CityWest Blvd.
Houston, Texas 77042

Responsible Official:

David Farris, Vice President

Technical Contact:

Chintan Mehta

2.2 Facility Background

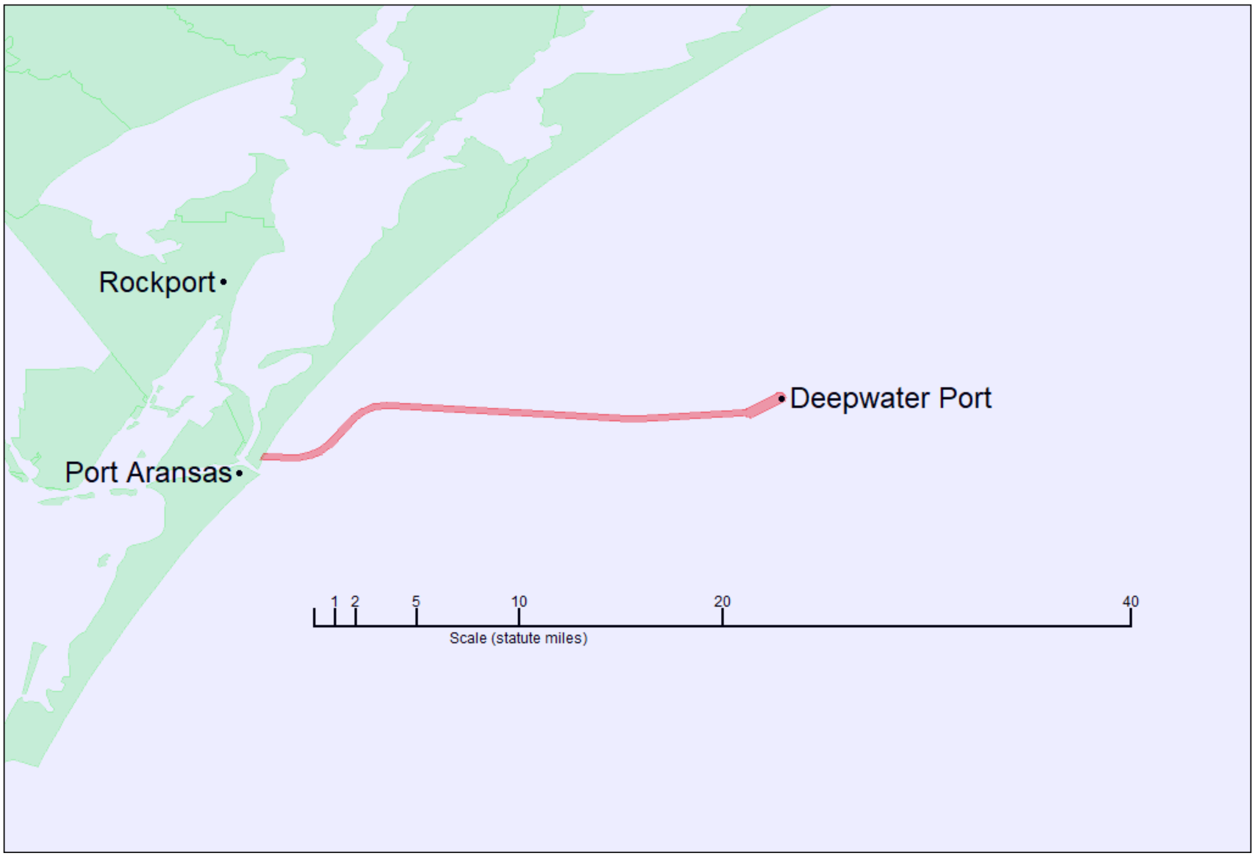
BWTT proposes to construct a deepwater port for export of crude oil via two Single Point Mooring (SPM) systems. The SPM's will be located at 27° 53′ 21.70″ N, 96°39′ 4.16″ W and at 27° 54′ 9.28″ N, 96° 37′ 41.23″ W, in BOEM lease block TX4, subdivisions 698 and 699 (see Appendix A). The facility will be approximately 18 statute miles from Matagorda Island at its nearest point and 26 statute miles from the entrance to Port Aransas. At the location of the deepwater port, the water depth is approximately 89 feet, which provides sufficient under keel clearance for a fully laden oil tanker in the Very Large Crude Carrier (VLCC) size range. A simplified depiction of the facility's location is presented in Figure 2-1. More detailed depictions are provided in Appendix A.

Land-based ports on the U.S. Gulf Coast do not provide sufficient draft for complete loading of VLCC's. In order to export crude oil, exporters must currently charter additional vessels to shuttle crude oil cargo between a shoreside terminal and a VLCC in an offshore lightering area. The proposed terminal will simplify the logistics associated with exporting crude oil on VLCC-size tankers. By conducting loading operations offshore, the project will also relieve inherent constraints and congestions in inland ports and waterways.

Loading of vessels is accomplished through two single point mooring (SPM) systems, each consisting of a pipeline end manifold (PLEM), a catenary anchor leg mooring (CALM) buoy, and hose strings. During loading operations, crude oil is pumped from the onshore valve and pipeline infrastructure to the deepwater port through two 30" offshore pipelines. The pipelines run along the seabed and terminate at a PLEM which is also affixed to the seabed. Each CALM mooring buoy is anchored by several catenary chains extending radially outward and down to the seabed. The buoy moves up and down with the tide and waves, and floats above the PLEM. The CALM buoy is partially submerged and its upper part is able to freely rotate about its base. One or more under-buoy hoses connect to the submerged portion of the CALM buoy and transfer crude oil from the PLEM to the CALM buoy. A floating hose string connects the CALM buoy to a tanker vessel in order to deliver crude oil.

Figure 2-1

Depiction of Facility Location (simplified)

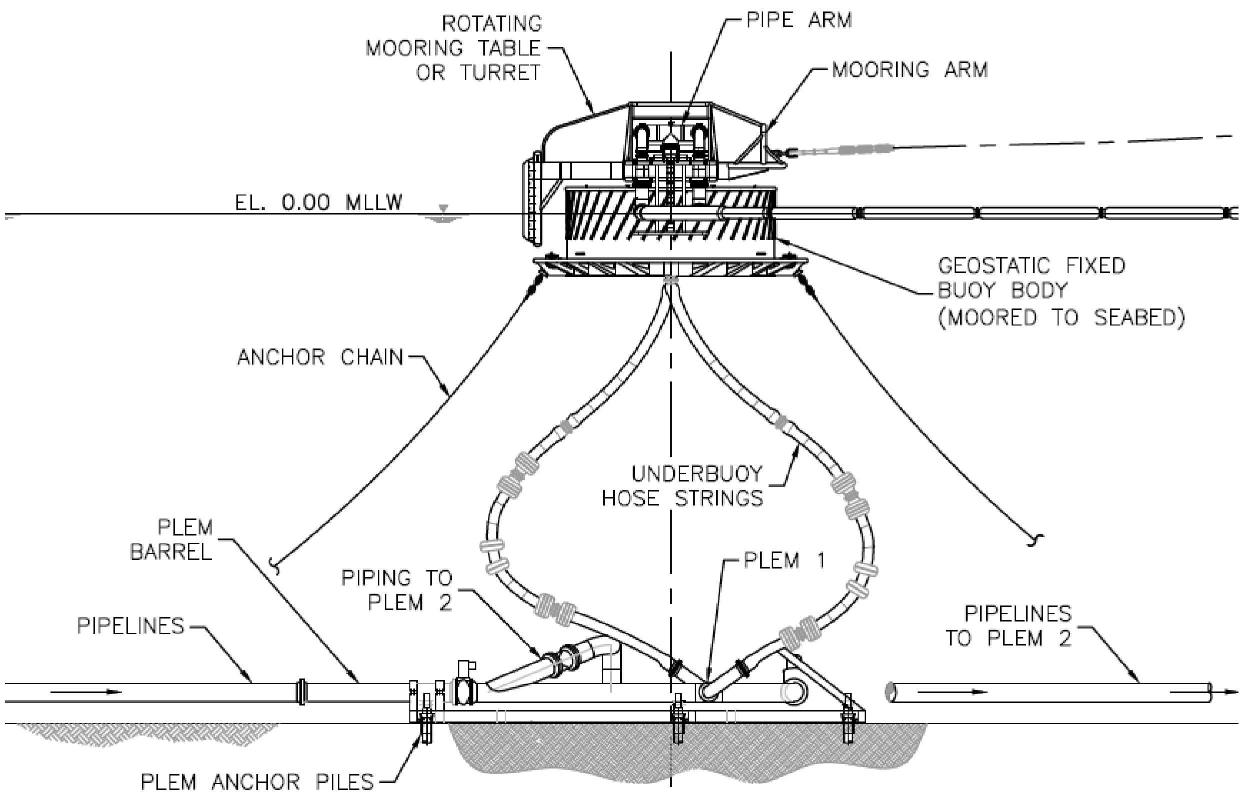


The proposed deepwater port will consist of subsea pipelines, single point mooring connections, mooring lines, a hose string and other necessary equipment. A shoreside pumping station will be used to transfer crude oil from an inshore storage terminal into the deepwater port. The shoreside and inshore facilities are not part of the deepwater port, and will instead be subject to Clean Air Act permitting requirements implemented by the State of Texas. These components, however, are described in detail in the concurrently-filed DWPA license application.

BWTT expects to begin construction on the deepwater port in June 2020, complete construction in October 2021, and start operations in November 2021.

Figure 2-2

Layout of PLEM, CALM Buoy, Under-Buoy Hose and Anchor Legs.



2.3 Applicability of Clean Air Act § 112(g) to the Terminal

The Clean Air Act requires all new major sources of HAP to meet MACT. If no applicable emission limitations have been established by EPA, then MACT must be determined case-by-case (CAA § 112(g)(2)(B)). As explained below, BWTT believes that MACT must be determined case-by-case for the proposed deepwater port.

EPA has promulgated NESHAP for the Marine Tank Vessel Loading Operations source category (40 CFR Part 63, Subpart Y, henceforth "MACT Y"),[1] and this is the source category which most closely resembles the proposed deepwater port. However, BWTT believes that the proposed terminal is not an affected source for purpose of MACT Y, that no promulgated standard applies to the proposed terminal, and that MACT must therefore be determined case-by-case for the proposed terminal.

A detailed analysis for non-applicability of MACT Y is provided in Section 5.

2.4 Process for Determining MACT

Regulatory provisions applying to case-by-case MACT determinations are at 40 CFR Part 63, Subpart B. Regulatory principles for determining MACT are at 40 CFR § 63.43(d). These require that MACT for a new major source be at least as stringent as the level of emissions control achieved in practice by the best controlled similar source, as determined by the permitting authority. This level of control is commonly referred to as the "MACT floor." Emissions reductions "beyond the floor" may also be required, considering the costs of achieving reductions and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction. The "beyond the floor" analysis must consider all "available information" (40 CFR § 63.41) and must also consider any relevant emission standards that have been proposed by the EPA administrator. MACT may consist of an operational or work practice standard if it is not feasible to prescribe or enforce an emission limitation.

EPA publication *Guidelines for MACT Determinations under Section 112(j) Requirements ("MACT Guidelines")*[2] provides a three-tiered process for determining MACT consistent with the principles at 40 CFR § 63.43(d). The MACT Guidelines provide the following process for determining the MACT floor, identifying feasible beyond the floor reductions, and for identifying MACT:[3]

- Tier I: Identify all affected emissions units and make a MACT floor finding for each emissions unit using available information provided by EPA, other permitting authorities, and/or the

[1] 60 FR 48399. September 19, 1995.

[2] EPA Publication 453/R-02-001. February 2002.

[3] MACT Guidelines at 3-7–3-12.

permit application. If the MACT floor cannot be identified or if it is equivalent to "no control," then proceed to Tier II. Otherwise, proceed to Tier III.

- Tier II: Identify all commercially available control technologies that have been successfully demonstrated in practice for similar emissions units. Eliminate technically infeasible control technologies, then determine the efficiency of all remaining technologies. A control technology is technically infeasible if:
    - There are structural, design, physical or operational constraints that prevent application of the control technology to the emissions unit;
    - The permit authority deems it unreasonable; OR
    - Its operational reliability and performance have not been demonstrated by approved methods under representative conditions.
- Tier III: Consider any available beyond the floor technologies, including technology transfer and innovative technologies used to control other emissions units. Beyond the floor technologies are subject to the same conditions of technical feasibility as those applying at Tier II. Specifically, "as in Tier II, the permitting authority should conduct an analysis to eliminate any technically infeasible control technology."[4] If a technically feasible beyond the floor technology is identified and that technology has an economic impact and incremental cost-effectiveness that is not unreasonable, or if it would control emissions of high risk or highly toxic pollutants (e.g., chromium), then controls more stringent than the MACT floor may be appropriate.

BWTT proposes to use the MACT Guidelines framework to determine MACT for the proposed facility. In order to facilitate the review process, BWTT has made an effort to identify in the present permit application all information necessary to establish a MACT floor, identify candidate "Tier II" control technologies, and identify available beyond the floor technologies. This analysis is presented in detail in Sections 6–7 of the application.

Based on BWTT's analysis, the MACT floor, based on the best controlled similar source, is no add-on controls. BWTT has identified three types of "Tier II" control technologies that could potentially be

[4] MACT Guidelines at 3-11.

used. However, none of these is technically feasible. Additional beyond the floor control technologies have also been considered, but none are technically feasible either.

Since BWTT has been unable to identify any feasible add-on control technologies, MACT is proposed in the form of a work practice standard. The proposed work practice standard includes two components: submerged fill and an inert gas management plan to minimize unnecessary venting of VOC vapors from tanker mast risers.

Suggested provisions for a Notice of MACT Approval (NOMA), including monitoring, reporting, recordkeeping and compliance provisions, are contained in Section 9 of this application. If EPA elects to issue a NOMA prior to processing BWTT's concurrently-filed Part 71 (Title V) application, the NOMA may be issued as a stand-alone authorization. BWTT requests that the NOMA be consolidated with the Part 71 operating permit at the time of its issuance. While BWTT has suggested NOMA provisions that it believes are reasonable, the permitting authority (in this case EPA) is ultimately responsible for the monitoring, reporting and recordkeeping requirements at permit issuance.[5]

2.5 Application Organization

This application contains the information specified in 40 CFR § 63.43(e)(2) and is organized as follows:

- Section 2 is the present introductory section (§§ 63.43(e)(2)(i)–(v)).
- Section 3 provides background information that informs the discussion in various parts of the application (§ 63.43(e)(2)(xii)).
- Section 4 provides the facility's potential to emit for HAP and VOC, and also quantifies the expected impact on reverse lightering operations currently taking place in the Gulf of Mexico (§§ 63.43(e)(2)(vi)–(ix)).
- Section 5 includes a detailed analysis of the applicability of case-by-case MACT for the facility, including an analysis of non-applicability for MACT Y (§§ 63.43(e)(2)(ii),(vii)).
- Section 6 is an analysis of the MACT floor for the facility (§ 63.43(e)(2)(xii)).
- Section 7 is a beyond the floor analysis for the facility (§ 63.43(e)(2)(xii)).

[5] MACT Guidelines at 5-6.

- Section 8 contains the proposed case-by-case MACT standard for the facility (§§ 63.43(e)(2)(x)–(xi)).
- Appendix A contains detailed maps for the facility (§ 63.43(e)(2)(xii)).

The present application may be treated as constituting two separate requests: a request for determination of non-applicability of MACT Y and a request for case-by-case MACT determination.

2.6 Acronyms and Abbreviations

Acronyms and customary abbreviations in this application are as follows.

Term	Gloss
AIS	Automatic Identification System
APCD	Air Pollution Control District
BAAQMD	Bay Area Air Quality Management District
Bbl	Barrel (42 U.S. gallons)
BOEM	Bureau of Ocean Energy Management, U.S. Department of the Interior
BWTT	Bluewater Texas Terminal LLC
CAA	Clean Air Act (42 USC § 7401 et seq.)
CALM	Catenary anchor-leg mooring
DWPA	Deepwater Port Act (33 USC § 1501 et seq.)
dwt	Deadweight tonnage
EMT	Ellwood Marine Terminal
EPA	Environmental Protection Agency
FPSO	Floating Production, Storage and Offloading Unit
FSO	Floating Storage and Offloading Unit
GIMT	Gaviota Interim Marine Terminal
GIS	Geographic Information System
GOLA	Galveston Offshore Lightering Area
HAP	Hazardous Air Pollutants
Jones Act	Merchant Marine Act of 1920, as amended (46 USC § 55101 et seq.)
LOOP	Louisiana Offshore Oil Port
LNG	Liquefied Natural Gas
MACT	Maximum Achievable Control Technology
MARAD	Maritime Administration, U.S. Department of Transportation
MBbl	1,000 Bbl
NESHAP	National Emission Standards for Hazardous Air Pollutants
NPRM	Notice of Proposed Rulemaking
OCIMF	Oil Companies International Marine Forum
OCSLA	Outer Continental Shelf Lands Act
OS&T	Santa Ynez Unit Offshore Storage and Treatment Unit
PLEM	Pipeline end manifold
SALM	Single anchor-leg mooring
SCAQMD	South Coast Air Quality Management District
SLA	Submerged Lands Act (43 USC § 1301 et seq.)

Term	Gloss
SPM	Single-point mooring
TCEQ	Texas Commission on Environmental Quality
USCG	U.S. Coast Guard
VLCC	Very Large Crude Carrier
VOC	Volatile Organic Compounds

Section 3
Technical Background

3.1 Introduction

This section collects general background information that may be referred to in other parts of the application, including the § 112(g) applicability analysis, the MACT floor demonstration, and the beyond the floor demonstration (Sections 5, 6, and 7, respectively). Sections 3.2 and 3.3 discuss useful categorizations of crude oil tankers and offshore loading facilities, respectively.

3.2 Classification of Crude Oil Tanker Vessels

Crude oil can be exported through tankers falling into different size ranges. In this application, the following terms may be used to refer to a crude oil tanker based on its size in deadweight tons (dwt) and its approximate cargo tank capacity.

Table 3-1
Classification of Crude Oil Tankers

Tanker Type	Size Range (dwt)	Typical Cargo Tank Capacity (Bbl)
Handymax	30,000–55,000	300,000
Panamax	60,000–75,000	380,000
Aframax	80,000–120,000	500,000
Suezmax	125,000–170,000	1,000,000
VLCC	250,000–320,000	2,000,000

Fundamental tanker economies of scale are such that the use of larger tankers is both more efficient and more cost-effective for long haul trade. For long-haul voyages between the North America and the Asia-Pacific region, use of a VLCC rather than an Aframax can create a savings on freight costs equivalent to approximately $1/Bbl of cargo.[6]

[6] Typical charter rates accessed February 14, 2019, at https://www.hellenicshippingnews.com/category/report-analysis/weekly-tanker-time-charter-estimates/.

A tanker's draft, which is the depth its keel extends below the water's surface, is dependent upon the vessel's design scantlings, water salinity, and the weight it carries (cargo, ballast, fuel, water, stores). Currently, crude oil export terminals in the United States Gulf Coast are capable of accommodating fully laden Panamax and Aframax tankers. Some terminals are able to accommodate a fully-laden Suezmax. While two terminals in Texas have recently practiced the partial loading of a VLCC, with an additional terminal expected to be online by early 2020, no shore-based terminal has sufficient draft to accommodate a fully laden VLCC. Complete loading of a VLCC in the Gulf of Mexico can be accomplished at the Louisiana Offshore Oil Port (LOOP), or via reverse lightering.

3.3 Classification of Offshore Loading Facilities

Facilities used to transfer cargo between a tanker vessel and an on-shore storage facility can be distinguished by their means of construction, operation, and their location with respect to the shore. Five main types of loading facilities are discussed, and these are summarized in Table 3-2.

Table 3-2
Classification of Offshore Loading and Unloading Facilities

Characteristic	Terminal Type				
	Causeway	Jetty	Platform	Multi-buoy	SPM
Distance from Shore	0–5 mi.	0–5 mi.	0–5 mi.	≈ 1 mi.	1–20 mi.
Mooring	Fixed	Fixed	Fixed	Fixed	Ship rotates freely
Attachment to Sea Floor	Pilings	Pilings	Pilings	Anchors	Anchors
Location of Piping	Above water	Above Water	Subsea	Subsea	Subsea
Access	Motor vehicle, service vessel	Helicopter, service vessel	Helicopter, service vessel	Service vessel	Service vessel
Loading Equipment	Loading Arms	Loading Arms	Loading Arms	Submersible Hose	Floating Hose

Classification of offshore loading facilities informs BWTT's proposed finding of applicability of 112(g) requirements, the MACT floor analysis, and the beyond the floor analysis. In order to complete the classification, BWTT identified approximately 70 offshore loading and unloading facilities around the world, with an emphasis on locating all offshore facilities in the United States. Facilities were identified through a two-step process. First, the registry numbers of various crude oil and chemical tankers were obtained, and AIS data transmissions for these vessels were purchased from a commercial vessel tracking service. Next, the vessels' itineraries over a particular time period (typically 3–6 weeks) were plotted with GIS software, and the ports where they called were identified through satellite photography. The following classification is based on review of the satellite photography as well as consultation of published material describing individual terminals or terminal construction practices.[7]

The typology arrived at by the preceding method is consistent in its main details with systems of classification presented in other publications, which emphasizes the broad relevance of the functional distinctions proposed.

Table 3-3
Comparison of Proposed Marine Terminal Classifications

Source	Category Name				
CCC 1988[8]		Fixed berth	Sea island	Multiple Buoy	Single Buoy
Marcus et al 1975[9]	Conventional pier		Sea island pier	Multiple buoy berth	SPM systems
Present work	Causeway	Jetty	Platform	Multi-buoy	SPM

The remainder of this section briefly discusses each of the five types of offshore loading facilities, providing satellite photographs where available.

3.3.1 Causeway- and Jetty-type Terminals

Causeway-type terminals are those which are connected to shore by a long causeway containing pipe racks and a road for motor vehicle access to the dock. Piping and utilities run along the causeway, and the berth itself consists of a dock containing loading arms and other equipment. In some cases, parking facilities, buildings, and other equipment may be located at different points along the

[7] Cf., for example, U.S. Department of the Interior Minerals Management Service. 1990. *Pacific Update: August 1987–November 1989*. OCS Information Program publication MMS 90-0013, for a listing of all marine terminals existing in California as of 1989.

[8] California Coastal Commission. December 1988. *Oil and Gas Activities Affecting California's Coastal Zone: A Summary Report*. Cf. Sec. VI.

[9] Marcus, Henry S. et al.. "Deepwater Ports in the United States: Technology in Perspective." in National Academy of Sciences. 1975. Background Papers on Seafloor Engineering. Volume I: National Needs in Seafloor Engineering. 107–130.

causeway. The majority of offshore loading terminals identified in the United States are of the causeway type, and these have distances to shore ranging from 0.3–0.9 statute miles. Such terminals are found at sites in Washington, California, New York, St. Croix, and Puerto Rico. Several causeway-type terminals have been observed in the Persian Gulf with above-water pipe racks extending up to five statute miles from shore.

Figure 4-1

Causeway-type terminals (clockwise from top right): Tranmere (UK), Ras Tanura (KSA), Anacortes (WA), Point Richmond (CA)

Jetty-type terminals are similar to causeway-type terminals in that they have above-water pipe racks and a loading berth consisting of a fixed platform with loading arms. However, the jetty does not provide for road access to the loading berths. These installations therefore have more limited space for installation of equipment in areas other than on the loading platform. Jetty-type terminals at international locations have been identified with berths up to 1.0 miles from shore.

3.3.2 Platform-type Terminals

Platform-type offshore terminals resemble causeway- and jetty-type terminals in that they are permanently fixed to the sea floor by pilings. The main difference is that they are not connected to the shore by a causeway or above-water pipe rack. Instead, piping runs along the seabed to shore, and access to the dock by personnel is via service vessel or helicopter. Like causeway- and jetty-type terminals, they tend to be sited in sheltered locations somewhat close to shore.

Six terminals of this type have been identified, two of which are located in the United States.[10] In the photographs, loading arms and mooring lines can be seen, as well as a helicopter landing pad in two cases. In one photograph, the piping run along the seabed is visible as a dark line exiting the upper-right corner of the photograph. The installation the greatest distance from shore (Venezuela) is approximately 3.6 statute miles from shore at its most distant point.

3.3.3 Multi-Buoy Mooring and Single Point Mooring (SPM)

Buoy-type facilities (multi-buoy and SPM) differ from jetty-type terminals in that they have no platform or loading arms. Tankers are moored in open-water locations by means of one or more buoys, and loading takes place through a hose connected to a pipeline end manifold (PLEM) attached to the sea floor.

Multi-Buoy Mooring

In a conventional, multi-buoy mooring (also known as "spread mooring"), a vessel is held in a relatively fixed position by means of two or more mooring buoys, as well as by its own anchors. Multi-buoy moorings are only suitable for relatively sheltered areas or where the directions of wind, wave and current are aligned along one prevalent direction.[11] Multi-buoy moorings are generally not used

[10] A platform-type terminal operated in San Francisco Bay prior to 1995 is discussed in more detail in Section ##.

[11] Pederson, K.I. 1977. Offshore Oil Loading Facilities. ASCE Seminar on Marine Construction. Accessed 13-Feb-2019 at http://www.sofec.com/whitePapers/1977%20Offshore%20Oil%20Loading%20Facilities.pdf.

for loading tankers greater than 100,000 dwt.[12] Numerous multi-buoy mooring facilities have been identified in the United States, almost all of which are located in California coastal waters (generally 0.5–1.5 statute miles from shore), though many of these have been abandoned and/or dismantled during the past 25 years. Loading of crude oil onto tankers via spread mooring buoys is documented as early as 1920 at locations along the Atlantic coast of Mexico.[13]

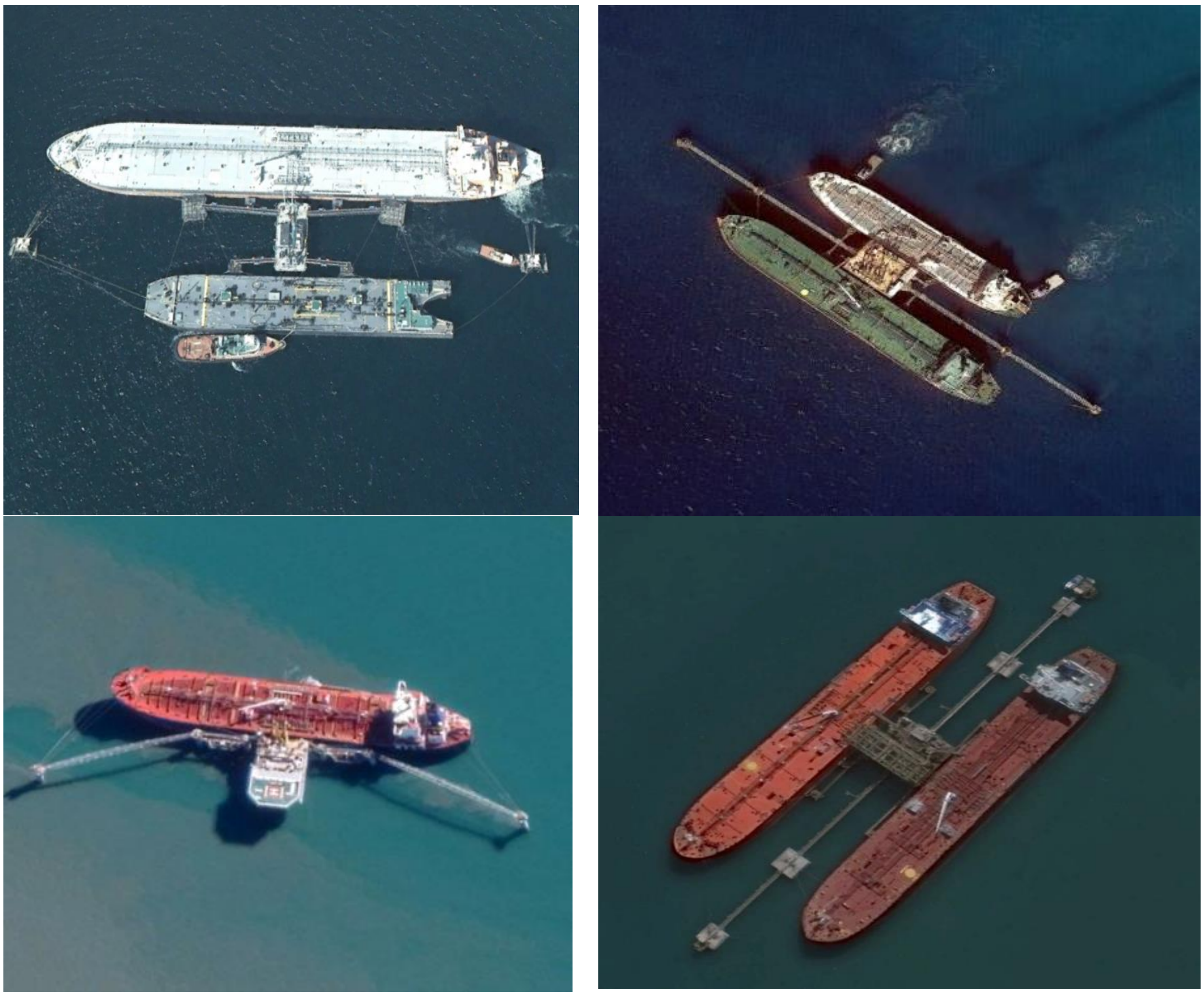
Multi-buoy moorings are normally designed with a submersible hose which rests on the seabed when not in use. These facilities are identifiable from satellite photography by a characteristic semi-elliptical array of buoys.

[12] Marcus, Henry. “Maritime Transportation Systems.” In Kildow, Judith ed. September 1977. *International Transfer of Marine Technology: A Three-Volume Study*. Massachusetts Institute of Technology Sea Grant Program. Report No. MITSG 77-20. II:81–142. at 123.-

[13] U.S. Navy Hydrographic Office. 1920. Central America and Mexico Pilot (East Coast). Washington: Government Printing Office. at 338, 344. Cf. also “Ocean-Bottom Filling Station.” *Popular Mechanics*. October 1951. 136–138.

Figure 4-2

Platform-type terminals (clockwise from top right): Freeport (Bahamas), Riverhead, NY, Drift River, AK, and Sitra (Bahrain)



3.3.4 Single Point Mooring

In a single-point mooring (SPM) or “monobuoy,” the tanker is moored at a single point only, and is thus allowed to freely rotate around the mooring as wind and sea conditions change. While SPM’s may be located near shore, they can also be installed in locations further from shore where sea conditions are more variable. SPM installations use a floating hose string which rests on the water surface when not in use, and can be identified from satellite imagery by the presence of the floating hose string. The first CALM SPM was placed into operation in 1959 at the Port of Dolaro, Sweden.[14]

While SPM's are reported as having been installed considerable distances from shore, publicly available satellite imagery is of lower resolution far from the shore, so photographs of the most distant installations are not available at high resolution. Installations observed near shore are at least one mile from shore. The distance from shore can be extended to the amount necessary to achieve the required draft. The LOOP installation noted previously is approximately 20 statute miles from shore, while the proposed SPM system will be approximately 18 statute miles from shore.

Figure 4-3 shows satellite photographs of four buoy-type facilities used to load liquids to/from shore, including one multi-buoy mooring and three SPM's.

[14] Lanquetin, B. 2005. "More than 30 Years' Experience with F(P)SO's and Offloading Techniques." Paper presented at the International Petroleum Technology Conference in Doha, Qatar, 21–23 November 2005.

Figure 4-3

Buoy-type offshore loading installations (clockwise from top right): Multi-buoy in El Segundo, (CA), SPM in Tetney (UK), SPM in Puerto José (Venezuela), and SPM in Barber's Point (HI)

Section 4
Emissions Summary

4.1 Introduction

In this section, HAP emission rates are estimated for the proposed facility, and the associated emission calculation methodology is explained.

4.2 VOC and HAP Emission Rates From Proposed Deepwater Port

Emissions are generated during loading operations when vapors in the headspace of a ship's cargo tank are displaced. A loading loss emission factor, expressed in units of lb/Mgal liquid loaded, is estimated following AP-42, Section 5.2, equation (1):

$$L_L = 12.46 \frac{SPM}{T}$$

S is a dimensionless saturation factor, assumed to be 0.2 for ship loading. P, M, and T represent the VOC vapor pressure, vapor phase molecular weight, and liquid surface temperature, respectively. The constant 12.46 is the inverse of the ideal gas constant, when expressed in units of (Mgal·psia)/(lb-mol·°R). For units of (MBbl·psia)/(lb-mol·°R), the leading coefficient is multiplied by 42.

In order to obtain the VOC emission rate, the loading loss is multiplied by the crude oil throughput in the appropriate units. In order to obtain the HAP emission rate, the VOC emission rate is multiplied by the vapor phase HAP mass fraction.

In order to estimate the vapor phase molecular weight and the HAP weight fraction, data collected by Hendler et al. are considered.[15] Hendler et al. report the complete speciation of vapors emitted from breather vents at tank batteries in 33 crude oil gathering stations in Texas (11 oil tank batteries and 22 condensate tank batteries). The 11 samples corresponding to the oil tank batteries were used as

[15] Hendler, Albert, Nunn, Jim, and Lundeen, Joe. *VOC EMISSIONS FROM OIL AND CONDENSATE STORAGE TANKS: FINAL REPORT*. 2009. Accessed February 14, 2019, at https://web.archive.org/web/20170115135023/http://files.harc.edu/Projects/AirQuality/Projects/H051C/H051CFinalReport.pdf.

the basis for estimation. Estimates were made based on the VOC species present, rather than total hydrocarbons (including methane and ethane). This is appropriate since much of the methane, ethane, nitrogen and carbon dioxide in a crude oil may weather out before it is exported. This assumption also makes the estimated HAP emission rate more conservative. One sample was discarded since its speciation was reported as 100% methane.

The molecular weight of each of the VOC species reported was weighted by that species' mass fraction in the sample. When vapor phase molecular weights were calculated in this manner, they ranged from 53.0 lb/lbmol to 109.8 lb/lbmol, with an average of 72.4 lb/lbmol. The loading loss factor is therefore calculated assuming a vapor phase molecular weight of 72.4 lb/lbmol.

The total HAP, taken as a fraction of the total VOC, ranges from 0.49% to 6.93%, with an average of 3.79%. Based on this information, the HAP emission rate is assumed to be 3.79% of the VOC emission rate.

T is taken as the monthly average annual ambient temperature for Corpus Christi, as reported in AP-42, Chapter 7, or 531.72°R (72.1°F).

The vapor pressure of the liquid is based on a maximum Reid Vapor Pressure of 9.5. This value is a specification in the tariff for the crude oil pipeline which will feed the deepwater port. Reid Vapor Pressure is converted to True Vapor Pressure using AP-42, Chapter 7, Equation 7.1-13b. At 72.1°F, RVP 9.5 corresponds to 8.44 psia. Therefore, P is taken to be 8.44 psia.

The loading loss factor is therefore calculated as 120.3 lb VOC/MBbl crude oil loaded, and 4.56 lb HAP/MBbl crude oil loaded.

The maximum hourly pumping rate for both SPM's combined is 80,000 Bbl/hr, and the estimated maximum annual throughput is 384,000,000 Bbl. The latter figure is based on an average of 16 VLCC's completely loaded per month. VOC and HAP emissions for the deepwater port are summarized in Table 4-1. Table 4-2 summarizes the calculation of emission factors following AP-42 Section 5.2, Equation (1). Since Table 4-2 is reproduced in the concurrently-filed PSD permit application, it depicts the development of emission factors for both HAP and Regulated NSR Pollutants.

Table 4-1
Total VOC and HAP Emissions for Deepwater Port

Pollutant	Short-term (lb/hr)	Long-term (tpy)
VOC	9624	23098
HAP	365	875

Table 4-2
Emission Factor Calculation Summary

Quantity	Unit	Value
Crude Oil RVP		9.5
Annual Avg. Temperature	°R	531.7
Crude Oil TVP	psia	8.44
CO_2 Partial Pressure	psia	2.1
Crude Oil Vapor Mol. Wt.	lb/lbmol	72.4
CO_2 Mol. Wt.	lb/lbmol	44
Ideal Gas Const.	(MBbl psia)/ (lbmol °R)	0.001911
Saturation Factor (VOC)		0.2
Saturation Factor (CO_2)		1
HAP Prevalence	t HAP/t VOC	3.79%
CH_4 Prevalence	t CH_4/t VOC	29.1%
H_2S Prevalence	t H_2S/t VOC	0.013%
CH_4 GWP	t CO_2e/t CH_4	25
L_L (VOC)	lb/MBbl	120.3
L_L (CO_2)	lb/MBbl	90.9
L_L (GHG)	lb (CO_2e basis)/ MBbl	965.9
L_L (HAP)	lb/MBbl	4.56
L_L (H_2S)	lb/MBbl	0.015

Section 5
Applicability of CAA § 112(g)

5.1 Introduction

EPA regulations at 40 CFR § 63.42(c) require a person who proposes to construct a new major source of HAP to obtain a case-by-case MACT determination if the proposed major source has not "*been specifically regulated or exempted from regulation under a standard issued pursuant to 112(d), section 112(h), or section 112(j)*" of the Clean Air Act. The purpose of the present section is to show that the proposed facility has not been specifically regulated under any source-specific § 112 standard, and is therefore required to obtain a case-by-case MACT determination.

The listed source category most similar to the proposed facility is the "marine tank vessel loading operations" source category, currently subject to regulation under 40 CFR Part 63, Subpart Y ("MACT Y"). MACT Y emission standards apply during "marine tank vessel loading operations," a term whose meaning derives from several related definitions at 40 CFR § 63.561, summarized below in Table 5-1 (emphasis added):

Table 5-1
Relevant MACT Y Terminology

Term	Definition
Marine tank vessel loading operation	any operation under which a commodity is bulk loaded onto a marine tank vessel from a **terminal**, which may include the loading of multiple marine tank vessels during one loading operation. Marine tank vessel loading operations do not include refueling of marine tank vessels.
Terminal	all **loading berths** at any land or sea based **structure(s)** that loads liquids in bulk onto marine tank vessels.
Loading berth	the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill marine tank vessels. The **loading berth** includes those items necessary for an offshore loading terminal.
Offshore loading terminal	a location that has at least one **loading berth** that is 0.81 km (0.5 miles) or more from the shore that is used for mooring a marine tank vessel and loading liquids from shore.

According to these definitions, a marine tank vessel loading operation must involve a "terminal," which consists of one or more "loading berths" at a "structure." An "offshore loading terminal" is a type of terminal, one of whose loading berths is at least 0.5 miles from shore. Finally, "loading berth," in the context of offshore loading terminals, is defined circularly to include items necessary for an offshore loading terminal.

BWTT believes that the pertinent regulatory terms are vague or ambiguous as they relate to the proposed facility, and that the regulatory text itself does not resolve the question of whether the proposed facility is a "marine tank vessel loading operation." First, the term "loading berth" is underspecified with respect to the "offshore loading terminal" subcategory because of its circularity of reference. Second, the definition of "offshore loading terminal" does not specify any outer distance. And finally, the term "structure" is not defined in the regulation, and its dictionary definition ("a building or edifice of any kind, esp. a pile of building of some considerable size and imposing appearance") [16] does not clearly include an SPM buoy.

Defined terms in MACT Y do not clearly encompass the proposed facility. Therefore, BWTT believes that in order to assess MACT Y applicability, it is necessary to examine the individual facilities used to define the "offshore loading terminal" subcategory in 1995, the types of control technologies considered in establishing the MACT floor for the subcategory, as well as the historical and legal context in which MACT Y was developed and promulgated. This examination supports BWTT's position that EPA did not intend for MACT Y to cover loading operations taking place beyond the state seaward boundary (generally 3 nautical miles).[17]

5.2 Offshore sources considered in establishing MACT Y

In order to identify offshore loading terminals considered in developing MACT Y, BWTT conducted a detailed review of the associated rulemaking docket (legacy rulemaking docket A-90-44).[18] Since the docket does not contain all relevant details about individual offshore terminals, review of the docket was supplemented by considering government publications pertaining to specific marine terminals

---

[16] Oxford English Dictionary. 2nd Edition.

[17] Cf. the definition of "boundaries" in the Submerged Lands Act, § 2(b) (43 U.S.C. § 1301(b)).

[18] In the following discussion, docket items are referred to by their document ID. The author, title, and date of each document is recorded in the associated docket sheet, available at https://www.regulations.gov/document?D=EPA-HQ-OAR-2003-0198-0002.

(or to marine terminals in general), as well as newspaper reports and the published statements of terminal owners and operators.

The MACT Y rulemaking docket indicates that EPA began work on developing a tank vessel emissions standard in 1990, prior to passage of the Clean Air Act Amendments in 1990.[19] Before 1993, EPA had intended to "*address all tank vessel emissions in a comprehensive, multi-faceted manner under Section 183(f)*"[20] rather than under the NESHAPS program. Subsequently, however, EPA published notice that it had changed its position and would regulate marine vessel loading operations under CAA § 112 as well as under § 183(f), consistent with the terms of a proposed consent decree.[21]

The earliest mention of the offshore terminals in the MACT Y docket are EPA staff notes from a July 24, 1991, meeting between EPA and representatives of Chevron.[22] Materials presented by Chevron indicated that it operated loading terminals at three offshore locations in the United States. The notes include a description of the facilities consistent with a spread mooring system as well as a recitation of technical difficulties associated with the use of a subsea vapor recovery pipeline (namely liquid condensate formation). The notes additionally identify the locations of four offshore terminals, and a comment that a comprehensive list could be obtained from USCG. In an August 30, 1991, follow-up letter to EPA, Chevron submitted a list of sixteen "offshore terminals with subsea lines."[23] The list includes all of the locations listed in a March 13, 1995, public comment submitted by Chevron,[24] which was one of two public comments that EPA identified as its source of information for setting the MACT floor for offshore loading terminals.[25] The offshore terminals identified by Chevron are listed below in Table 5-2. Chevron's list has been supplemented with an indication of the mooring geometry, the type of operations conducted (loading vs. unloading), and the years during which each terminal was operated.

---

[19] A-90-44 II-A-18.

[20] 57 FR 31576, 31586. July 16, 1992.

[21] 58 FR 60021. November 12, 1993.

[22] A-90-44 II-E-35. Except where context dictates otherwise, common names such as "Chevron" are used in this application to refer to business entities and their affiliates, rather than the actual legal names of specific entities (e.g., Chevron USA Inc.).

[23] A-90-44 II-E-37.

[24] A-90-44 IV-D-136.

[25] Cf. A-90-44 IV-B-2, sec. 4.2.

Table 5-2
Offshore Terminals with Subsea Lines Mentioned in the Docket

Location	Distance from Shore	Type	Facility Served	Cargo loaded/unloaded	Years in Operation
Drift River, AK[26]	1.8 miles[27]	Platform	Onshore oil production (tanker across Cook Inlet)	Loading oil	Decommissioning scheduled for 2019.[28]
Hercules, CA	0.6 miles[29]	Platform	Refinery	Product Loading	Refinery closed 1995, limited terminal operation until 1997.[30]

[26] Alaska Department of Environmental Conservation (ADEC). September 16, 2016. Statement of Basis, Permit No. AQ0190TVP03, issued to Cook Inlet Pipe Line Company.

[27] Satellite imagery dated August 27, 2016 at 60° 33′ 23.45″ N, 152 08 25.32 W. Via Google Earth.

[28] The Regulatory Commission of Alaska. March 8, 2019. Order Granting Applicatoin, In the Matter of the Application Filed by COOK INLET PIPE LIEN COMPANY for Approval to Permanently Discontinue Use of and Abandon Drift River Terminal and Tank Farm, Christy Lee Platform, and Drift River Segment and for Approval to Access DR&R Fund. P-18-009, Order No. 4: Finding Use of Facilities no Longer Required, Issuing Construction Permit, Authorizing Access to DR&R Fund, Requiring Filing, and Redesignating Commission Panel.

[29] Satellite imagery dated July 5, 1993, at 38° 03′ 15.62″ N, 122° 16′ 21.69″ W, via Google Earth.

[30] California Energy Commission. California Oil Refinery History. Accessed April 15, 2019, at https://www.energy.ca.gov/almanac/petroleum_data/refinery_history.html.

Location	Distance from Shore	Type	Facility Served	Cargo loaded/unloaded	Years in Operation
Moss Landing, CA	0.8 miles[31]	Multi-buoy[32]	Electric Utility	Unloading fuel oil[33]	Fuel oil no longer fired.[34]
Estero Bay, CA (Chevron)	0.5 miles, 0.6 miles[35]	Multi-buoy[36]	Offshore oil production	Loading oil[37]	Ceased operations in 1999.[38]
Morro Bay, CA (PG&E)[39]	0.7 miles[40]	Multi-buoy	Electric Utility	Unloading fuel oil	Ceased unloading operations in 1990.

[31] County of Monterey, California. n.d. Moss Landing Community Plan. Accessed April 17, 2019 at http://www.co.monterey.ca.us/planning/Long-range-planning/Moss_Landing_Community_Plan/Moss_Landing_Community_Plan.pdf. At 89.

[32] U.S. Dept. of the Interior. April 1974. Final Environmental Impact Statement. Deepwater Ports: TO accompany legislation to authorize the Secretary of the Interior to regulate the construction and operation of deepwater port facilities (henceforth "DWPA EIS"). at I-24.

[33] California Coastal Commission. 1988. Oil and Gas Activities Affecting California's Coastal Zone. at 57.

[34] "State releases cleanup plan for Moss Landing power plant." The Mercury News. March 30, 2010. Accessed April 15, 2019, at https://www.mercurynews.com/2010/03/30/state-releases-cleanup-plan-for-moss-landing-power-plant/.

[35] California Coastal Commission. August 27, 1999. Item Number W-14a. Revised Findings. Application File No. E-98-26. Chevron Pipeline Company. At 8 (describing the locations of two loading berths).

[36] DWPA EIS at I-24.

[37] A-90-44 II-E-40.

[38] California Coastal Commission. August 27, 1999. Item Number W-14a. Revised Findings. Application File No. E-98-26. Chevron Pipeline Company.

[39] DWPA EIS at I-24.

[40] California State Lands Commission. February 2018. Initial Study/Mitigated Negative Declaration. Dynegy Morro Bay, LLC Morro Bay Power Plant Marine Terminal Decommissioning Project. at 1-3–1-4. (Report cover depicts aerial photograph of mooring buoys and tanker.)

Location	Distance from Shore	Type	Facility Served	Cargo loaded/unloaded	Years in Operation
Gaviota, CA	0.7 miles[41]	Multi-buoy	Offshore oil production	Loading oil	Built in 1988. Operated 8/1/93–1/31/94.[42]
Goleta, CA[43]	0.5 miles[44]	Multi-buoy	Offshore oil production	Loading oil	Ceased operations in 2012.
Point Conception, CA[45]	0.4 miles[46]	Multi-buoy	Offshore oil production	Loading oil	Last barge loaded in 1987. Abandoned as of 1993.
Mandalay Beach, CA[47]	1.0 miles	Multi-buoy	Electric Utility	Unloading fuel oil	Last barge loaded in 1991.

[41] California State Lands Commission. April 28, 1993. Calendar Item 47 concerning Lease PRC 7075. Authorization to Issue Industrial Lease for Offshore Marine Terminal.

[42] Chevron Corporation. SEC Form 10-K (annual report) for period ending March 31, 1993. March 25, 1994.

[43] County of Santa Barbara. March 2011. Draft Environmental Impact Report for the Ellwood Pipeline Company Line 96 Modification Project. Santa Barbara County EIR No. 09EIR-00000-00005.

[44] Satellite imagery dated November 28, 2006 at 34° 24′ 28.50″ N, 119° 53′ 23.15″ W. Via Google Earth.

[45] County of Santa Barbara Planning and Development. Energy Division. Unocal Point Conception Decommissioning Project. Accessed April 4, 2019 at http://www.sbcountyplanning.org/energy/projects/unocalPtConception.asp.

[46] Padre Associates, Inc. 2002. Current Marine Terminal Decommissioning Projects. Environmental Issues and Project Responses. Accessed April 15, 2019 at https://web.archive.org/web/20181130073234/https://www.slc.ca.gov/About/Prevention_First/2002/Decommissioning-Current.pdf.

[47] Ibid.

Location	Distance from Shore	Type	Facility Served	Cargo loaded/unloaded	Years in Operation
El Segundo, CA	1.4– 1.5 miles[48]	Multi-buoy[49]	Refinery	Unloading oil, loading product	In operation.
Huntington Beach, CA	1.4 miles[50]	Multi-buoy	Refinery	Unloading oil, loading product	Refinery closed in 1991.[51]
Carlsbad, CA[52]	0.5 miles	Multi-buoy	Electric Utility	Unloading fuel oil	Plant conversion to gas prior to 1990, abandoned c. 1999.
Barbers Point, HI (Chevron)	1.4 miles[53]	Multi-buoy	Refinery	Unloading oil, loading product.[54]	Refinery closed in 2018,[55] partial transfer of assets to neighboring refinery.

48 South Coast Air Quality Management District. October 30, 2018. Facility Permit to Operate issued to Chevron Products Co. Facility ID 80030. Revision # 88. At 142–143 (referring to three berths).

49 Satellite imagery dated November 2, 2005 at 33° 54′ 15.26″ N, 118° 27′ 08.01″ W. Via Google Earth.

50 Coast Guard California Spill Report Stirs Fuss. July 2, 1990. Oil & Gas Journal.

51 "Shutting Down: Golden West Refinery Closure will Cost 280 their Jobs." December 22, 1991. Los Angeles Times. Accessed April 15, 2019 at https://www.latimes.com/archives/la-xpm-1991-12-22-hl-1372-story.html.

52 California State Lands Commission. December 2015. Mitigated Negative Declaration. Cabrillo Power I LLC Encina Marine Oil Terminal Decommissioning Project.

53 Satellite imagery dated January 29, 2013 at 21° 16′ 40.68″ N, 158° 04′ 18.99″ W. Via Google Earth.

54 A-90-44 II-E-35 ("*mainly receiving*").

55 "Island Energy to end Hawaii refining business, sell assets." August 31, 2018. Oil and Gas Journal.

Location	Distance from Shore	Type	Facility Served	Cargo loaded/unloaded	Years in Operation
Barbers Point, HI (Hawaiian Ind. Ref.)[56]	1.5 miles[57]	SPM	Refinery	Unloading oil, loading product	In operation
River Head, NY[58]	1.3 miles[59]	Platform	Bulk terminal	Product loading and unloading	In operation
Port Fourchon, LA (LOOP)	20 miles[60]	SPM	Deepwater Port	Unloading oil (prior to 2018), loading and unloading oil (since 2/18/2018).[61]	In operation

56 The Natural Resource Trustees for the Tesoro Oil Spill, Hawaii. November 2000. Final Restoration Plan and Environmental Assessment for the August 24, 1998 Tesoro Hawaii Oil Spill (Oahu and Kauai, Hawaii).

57 Par Pacific Holdings, Inc. March 11, 2019. SEC Form 10-K for reporting period ending 12/31/2018. ("*On Oahu, the system begins with our SPM located 1.7 miles offshore of our Hawaii refinery. This SPM allows for the safe, reliable, and efficient receipt of crude oil shipments to the Hawaii refinery, as well as both the receipt and export of finished products.*")

58 New York State Department of Environmental Conservation. April 12, 2016. Permit Review Report. Permit ID 1-4730-000023/00030. Issued to United Riverhead Terminal Inc.

59 Satellite imagery dated March 6, 2012 at 41° 00′ 01.51″ N, 72° 38′ 47.83″ W. Via Google Earth.

60 Satellite imagery dated March 12, 2013 at 28 51 45.06 N, 90 01 26.29 W. Via Google Earth.

61 "First exported VLCC from Louisiana Offshore Oil Port arrives in China: In the LOOP." April 24, 2018. S&P Global Platts. Accessed April 15, 2019 at https://blogs.platts.com/2018/04/24/vlcc-loop-export-arrives-china-loop/.

EPA staff notes from an April 20, 1994, meeting with representatives of TOSCO refer to the list provided by Chevron and its relevance to setting the MACT floor:

> *Mr. Markwordt stated that anecdotal data mentioned during the Chevron meeting indicated that there were approximately 16 offshore terminals in the U.S. At least 3 of these offshore terminals appeared to have installed emissions controls*.[62]

Because Chevron's 1991 letter did not identify specific control measures undertaken at any of the listed terminals, it is presumed that EPA staff reviewed the list and made inquiries into the specific control measures in practice. Terminals which practiced unloading only (LOOP and the four electric utilities) would not have had any loading emissions. The three controlled terminals referred to are most likely the following:

- Pacific Refining operated a refinery in Hercules, CA, prior to 1995. The loading platform would have been subject to BAAQMD Rule 8-44. Although the exact nature of the control system has not been identified, Chevron's 1995 comment letter states that it was "similar to a wharf-type terminal where the vapor control equipment is installed on the platform itself."[63] BWTT believes this facility is the "platform" referred to in BAAQMD's 1995 comment letter.[64]
- The Ellwood Marine Terminal (EMT), located in Goleta, CA, served to transport to market crude oil that was produced offshore at Platform Holly (in California coastal waters) and treated at an onshore processing facility. Chevron's 1995 comment letter remarked that EMT was "served by a barge that has its own vapor control equipment." This remark appears to refer to the use of a dedicated fleet of controlled tankers, rather than an emissions-controlling workboat of the type described in its June 25, 1992, presentation to EPA.[65] In order to comply with Santa Barbara APCD Rule 327, only specially-designed vessels with onboard vapor recovery systems (refrigeration-based) were permitted to take on cargo from

---

[62] A-90-44 II-E-49.

[63] A-90-44 IV-D-136.

[64] A-90-44 IV-D-80.

[65] A-90-44 II-E-40. The presentation concerned a contemplated control project at Chevron's Estero Bay loading terminal, which would eventually become subject to San Luis Obispo County APCD Rule 427.

the terminal. Two ocean-going barges, the *Jovalan* and the *Olympic Spirit*, were used for these purposes.[66]

- The Gaviota Interim Marine Terminal (GIMT), located in Gaviota, CA, was developed to serve a similar function to EMT. It was intended to replace a prior multi-buoy offshore terminal operated by Getty Oil, and would transport oil produced at the Point Arguello field (offshore in federal waters) which had been processed at an onshore plant. GIMT was also subject to Santa Barbara APCD Rule 327, and was designed with a vapor control system based on the use of subsea vapor lines that carried VOC vapors to an onshore control device. Two 10 ¾”–12” polyethylene vapor lines were installed in a loop to allow for pigging (necessary to remove liquid condensate). The vapor return lines traveled approximately 3500 ft. under water to the onshore portion of the terminal.[67] The MACT Y docket contains correspondence between USCG and Chevron discussing the difficulties in handling liquid condensate formed in the vapor recovery line,[68] as well as a presentation from Chevron noting that such lines were “extremely difficult to permit.”[69]

  The comment about difficulties likely refers to the ordeals faced by companies interested in developing the Point Arguello field (including Chevron) and operating GIMT. Due to conflicts with the California Coastal Plan (which generally discouraged tankering of crude oil in the Santa Barbara channel), operators experienced delays in receiving the necessary permits to operate the terminal, and the eventual permits required operations to cease on February 1, 1994, if binding agreements for construction of a pipeline were not made.[70] Such agreements were not timely made, and the terminal ceased operations after only six months. Chevron argued for exclusion of this source in its 1995 comment letter, noting that “the terminal does not have permission to tanker.”[71]

---

[66] County of Santa Barbara. March 2011. Draft Environmental Impact Report for the Ellwood Pipeline Company Line 96 Modification Project. Santa Barbara County EIR No. 09EIR-00000-00005.

[67] California Coastal Commission. May 23, 1997. Permit Amendment Staff Recommendation. Application File No. E-92-6-A2. Gaviota Terminal Company (GTC). In-place abandonment and/or removal of the offshore components of the Gaviota Interim Marine Terminal.

[68] A-90-44 II-D-49.

[69] A-90-44 II-E-40.

[70] California State Lands Commission. April 28, 1993. Authorization to Issue Industrial Lease for Offshore Marine Terminal (lease block PRC 7075). Calendar Item 47.

[71] A-90-44 IV-D-136.

In a July 8, 1992, letter to EPA, Chevron had suggested a definition of "offshore loading terminal" for the purposes of creating a subcategory for such installations.[72] EPA included subcategorization as an option in its May 13, 1994, Notice of Proposed Rulemaking (NPRM)[73] using a definition based on that suggested by Chevron. The definition contained in the NPRM would have included mooring buoy-based terminals, and would have excluded causeway- and jetty-type terminals. Platform-type terminals would likely have been included as well, though it's not certain whether they would have qualified as an "open water location."

During the public comment period, owners of causeway-type terminals with loading berths at least 0.5 miles from shore[74] argued that their facilities should be exempt from MACT Y control requirements. Although Chevron had represented its Richmond, CA, "Long Wharf" terminal as an onshore terminal (in contrast to El Segundo), BAAQMD submitted a comment observing that the facility was controlled (consistent with Chevron's representations), and should be considered in setting the MACT floor for offshore loading terminals.[75]

On consideration of public comments, EPA revised the definition of the "offshore loading terminal" subcategory to refer to all terminals with at least one loading berth 0.5 miles or more from shore (thus including causeway- and jetty-type terminals). The memorandum to the docket detailing recalculation of the MACT floor for offshore loading terminals indicated that there were "*no more than 20 marine tank vessel loading terminals with subsea lines that are at least 0.5 miles from shore … [none of which] presently control loading emissions*."[76] Since the memorandum specifically identifies Chevron's 1995 comment letter as the source of its information, it appears that EPA accepted Chevron's arguments for disregarding EMT and GIMT in setting the MACT floor (the former did not use controls installed at the terminal itself, and the latter had lost authorization to operate its facility). The memorandum goes on to note that an unknown number of additional offshore terminals

[72] A-90-44 II-D-55. ("*Such a terminal is an open water location for mooring a marine tank vessel and loading either Crude Oil or Gasoline through subsea lines from shore.*")

[73] 59 FR 25004.

[74] E.g., Amerada Hess Corporation, referring to a causeway-type terminal at its St. Croix refinery. A-90-44 IV-D-140.

[75] A-90-44 IV-D-80.

[76] A-90-44 IV-B-2 at 8.

existed, which did not use subsea lines, two of which were known to control emissions. The source of information given is BAAQMD's 1995 comment letter.[77]

To summarize, the MACT Y rulemaking docket shows that EPA began considering the issue of offshore loading terminal as early as 1991, and had a list of specific facilities that would potentially be subject to the rule. The list included sixteen offshore terminals, eleven of which were actually used for loading operations. Of the eleven facilities used for loading, three were of the platform type, seven were of the multi-buoy mooring type, and one was of the SPM type. All loading terminals were located in state territorial waters. Although EPA was aware of control systems that had been designed for two mooring buoy-type terminals, neither control system was considered in setting the MACT floor.

5.3 Discussion

The DWPA defines a "deepwater port," in relevant part to

> mean[] any fixed or floating manmade structure other than a vessel, or any group of such structures, that ***are located beyond State seaward boundaries*** and that are used or intended for use as a port or terminal for the transportation, storage, or further handling of oil or natural gas for transportation to or from any State, except as otherwise provided in section 1522 of this title, and for other uses not inconsistent with the purposes of this chapter, including transportation of oil or natural gas from the United States outer continental shelf;
>
> (B) includes all components and equipment, including pipelines, pumping stations, service platforms, buoys, mooring lines, and similar facilities ***to the extent they are located seaward of the high water mark***;
>
> …

[77] The report inaccurately implies that the Hercules, CA loading platform lacked subsea lines. Since BAAQMD did not identify this source by name, it is probable that the contractor drafting the report was not aware of the specific facility being referred to. Also, as noted above, five of the listed terminals did not conduct loading operations.

(D) ***shall be considered a "new source" for purposes of the Clean Air Act*** (42 U.S.C. 7401 et seq.), and the Federal Water Pollution Control Act (33 U.S.C. 1251 et seq.).[78]

The DWPA therefore specifies that a deepwater port is a specific type of "new source" consisting of port or terminal facilities located beyond the "state seaward boundaries," which are, at a minimum, three nautical miles from shore.[79] The deepwater port also includes other equipment located seaward of the high water mark. In other words, the DWPA defines a specific type of source for purposes of the Clean Air Act, none of whose components are located on land.

In contrast, section 183(f) of the Clean Air Act, whose implementation ultimately led to promulgation of MACT Y, directs EPA to consider, to the extent practicable, only those emissions standards that would apply to "loading and unloading facilities and not to tank vessels."[80] Consequently, when developing its proposed regulations, EPA explicitly stated its intent for control requirements to apply to terminals, rather than to individual vessels.[81] Consistent with this direction, and as noted above, one offshore facility achieving control by limiting loading to barges with onboard control systems was disregarded when setting the MACT floor for offshore loading terminals.

While deepwater ports, by definition, exclude all land-based equipment, the MACT Y "offshore loading terminal" subcategory was developed with a primary emphasis on land-based control systems. As comments in USCG's companion rulemaking make clear, the regulations responded in part to a proliferation of control requirements issued by State air pollution control agencies.[82] State

---

[78] 33 USC § 1502(10) (emphasis added).

[79] *See* 33 USC § 1518 (noting that the nearest adjacent coastal state is the state "whose seaward boundaries if extended beyond 3 miles, would encompass the site of the deepwater port). The Submerged Lands Act grants to Texas and Florida the submerged lands within three marine leagues, which is nine nautical miles, off the Gulf coast, whereas other states received such lands only out to three nautical miles. *See United States v. Louisiana*, 363 U.S. 1, (1960); *United States v. Florida*, 363 U.S. 121, 129 (1960). In 1995, the DWPA language demarcating the geographic jurisdiction of the Act was somewhat different. That version of the statute defined a "deepwater port" as one "located beyond the territorial sea and off the coast of United States …" (33 USC §1502 (10) (1995 ed.). The provision of the DWPA, however, clarifying the three miles geographic jurisdictional limit for the nearest adjacent coastal state was three miles in 1995 and remains so today. 33 U.S.C. § 1518.

[80] CAA § 183(f)(1)(A). The Committee Report for the House Version of the Clean Air Act Amendments of 1990 explains that "*[t]he emphasis on loading and unloading facilities is intended to minimize problems that might be created by subjecting vessels to inconsistent requirements at different ports.*" House Report 101-490 at 254–255.

[81] 59 FR 25009. May 13, 1994.

[82] 55 FR 25396. June 21, 1990 ("*[s]ome states … have issued requirements for the control of [VOC] emissions from tank vessels…*"); Id. at 25407 ("*…these types of facilities [i.e., loading at mooring buoys]*

regulation of marine vessel emissions was cited as a concern which ultimately led to development of national emission standards by EPA.[83] BWTT believes that the absence of any discussion of MACT Y as it pertained to DWPA sources is consistent with an assumption that the regulations were only intended to apply within state territorial waters (i.e., "offshore loading terminal" and "deepwater port" have non-overlapping meanings). This is consistent with EPA's reasoning in excluding lightering operations from the affected source category (they "do not take place at onshore terminals"[84]).

In addition to offshore loading operations subject to the Deepwater Ports Act, there also exist offshore loading operations that are regulated under the Outer Continental Shelf Lands Act (OCSLA).[85] OCSLA applies primarily to exploration, development and production of minerals from submerged lands and sea beds beyond state seaward boundaries, and generally requires that the laws of the United States apply on the Outer Continental Shelf in the same manner as they would to activities located on land.

OCSLA operations include floating production, storage, and offloading (FPSO) units which load crude oil onto tankers. Two such units are known to currently operate in the Gulf of Mexico.[86] While the MACT Y definition of "source" excludes "offshore drilling platforms" it is not immediately obvious that this exclusion should apply to FPSO's: FPSO's are not platforms and they are not used for drilling.[87] FPSO's would not qualify for the "lightering operations" exclusion either, since they do not transport crude oil, and are therefore not "marine tank vessels." Although they are treated as "points in the United States" for purposes of the Jones Act, they do not load liquids from shore, and would likely not qualify as "offshore loading terminals" under MACT Y.

---

present some unique problems … [h]owever, exempting them from the regulation is not possible since some states may require offshore terminals to collect cargo vapors emitted from vessels within their jurisdictional waters.")

83 59 FR 25005.

84 *Id*. at 25007.

85 43 U.S.C. § 1331 et seq.

86 These are the *BW Pioneer* and the *Turritella*.

87 BWTT cannot locate any rationale for the exclusion of offshore drilling platforms in the rulemaking docket.

FPSO's conduct loading operations, and are similar to Deepwater Ports in several respects.[88] For example, the "Offshore Storage & Treatment" (OS&T) facility, operated by Exxon Corporation from 1981–1993 (the first FPSO located in U.S. waters),[89] received produced oil through a single point mooring buoy (SALM-type) and loaded processed oil onto a tandem-moored tanker. Since OS&T was located beyond California's seaward boundary, confusion existed as to whether it should be subject to the Deepwater Ports Act, with the issue of non-applicability eventually being settled by the courts.[90]

Though it is not mentioned in the docket, BWTT presumes that EPA was aware of the OS&T source at the time MACT Y was being developed, and that EPA intended to exempt OS&T and similar sources from the regulation. EPA issued a determination in 1978, finding that PSD permitting and California SIP requirements applied to OS&T.[91] The decision was eventually reversed in court due to a jurisdictional conflict between EPA and the Interior Department.[92] Congress addressed the issue during passage of the Clean Air Act Amendments of 1990 by inserting what is now Section 328 of the Clean Air Act. Under this Provision, EPA has authority to enforce Clean Air Act regulations, including the SIP of the nearest coastal state, except for in portions of the Gulf of Mexico (including areas offshore of Texas). The level of attention that it attracted strongly suggests that EPA was reasonably aware of the source and its operations.

BWTT believes that an intent to exempt sources outside of state jurisdictional waters explains the lack of information useful to discern how MACT Y should be applied to sources covered by the Deepwater Ports Act and the OCSLA. For example, BWTT cannot identify any comment about differential application of MACT Y to OCSLA offshore loading operations where EPA's jurisdiction varies according to CAA § 328. It is also unclear whether production platforms and/or FPSO's were intended to fall under the "offshore drilling platforms" or "lightering operations" exclusions. Finally, BWTT cannot identify any discussion of EPA's proposed half-mile test for source aggregation, and

---

[88] In fact, MARAD regulations contemplate the refurbishment of OCSLA equipment for use as a deepwater port (33 CFR § 148.105(s)).

[89] ExxonMobil Corp. History of the Santa Ynez Unit. Accessed April 3, 2019 at https://www.syu.exxonmobil.com/history.

[90] *Get Oil Out! Inc. v. Exxon Corp*. 586 F.2d 726 (CA9 1978) (henceforth "GOO v. Exxon").

[91] 43 FR 16393. April 18, 1978.

[92] *California v. Kleppe*. 604 F.2d 1187 (CA9 1979).

how it should be applied at deepwater ports using multiple mooring buoys separated by more than 0.5 miles from each other. The simplest explanation for the lack of information in the docket is that the regulation was never intended to apply to facilities specifically regulated by DPA and OCSLA (i.e., facilities outside of state jurisdictional waters). This is consistent with several other facts detailed above: No loading terminals in federal waters were considered, though at least one existed.[93] Onboard-type control systems were specifically excluded from consideration, even though this is the most plausible means of control for a terminal far from shore (cf. discussion in Secs. 6–7). And finally, an important overall objective of the rulemaking was to standardize equipment at marine terminals subject to a variety of *state-level* control requirements.

[93] In addition to OS&T, other offshore loading operations are referred to in *GOO v. Exxon*: a letter from USCG is excerpted in the opinion, reading in part:

> *Indeed, as you are aware, there are a number of permanently moored barges in the Gulf of Mexico on the U.S. continental shelf which function exactly in the manner that you intend to employ off Santa Barbara, and have done so for several years*.

Section 6
Case-by-case MACT Analysis (Tiers I–II)

6.1 Introduction

A new major source of HAP must comply with a level of control that is at least as stringent as that achieved by the best-controlled existing similar source. The MACT floor analysis therefore consists of identifying all existing similar sources within the source category or subcategory along with the level of HAP reduction achieved at each, ranking them by order of effectiveness, and selecting the most effective option. This represents the MACT floor.

As noted in Section 5, P66 believes that the proposed facility is not part of the same source category that is subject to MACT Y, because MACT Y does not apply to loading operations taking place beyond the state seaward boundaries, which, at a minimum, are three nautical miles beyond the state coastline.[94] Although only two of them remain in operation today, the proposed finding of MACT Y non-applicability entails that the offshore loading facilities identified in the rulemaking docket are not "similar facilities" for the purposes of a case-by-case MACT review, nor is any other source subject to, or specifically exempted from MACT Y.[95]

This section contains the Tier I (MACT floor) analysis described in EPA's MACT Guidelines guidance. Since the MACT floor consists of specific work practices with no add-on controls, BWTT has also conducted a Tier II analysis (identifying all commercially available controls), which is also contained in the present section.

6.2 MACT Floor (Tier I)

The proposed facility contains two emissions units of the same type: crude oil loading operations conducted using a CALM buoy. During loading operations, VOC vapors contained in the tanker's

[94] 43 U.S.C. § 1312; *supra* note 79.

[95] For example, the proposed SPM system described in the April 5, 2018, decision letter issued by EPA's Assistant Administrator (OAR), concerning the Limetree Bay Terminals facility in St. Croix, is presumably exempted from MACT Y because of EPA's finding that it was part of the same emissions unit as an existing offshore loading terminal (causeway-type).

cargo tanks, along with inert gas, are displaced by the liquid cargo and vented through the tanker's mast risers.

The only marine terminal in the United States which conducts loading operations beyond state seaward boundaries is the Louisiana Offshore Oil Port (LOOP). The facility has functioned since 1981 as an unloading port. BWTT has not identified any requirements for control of air emissions from loading operations at LOOP, and presumes that the facility operates without add-on controls for air emissions. The facility's Deepwater Port license was last amended in 2000,[96] and BWTT cannot find any indication LOOP became subject to additional licensing requirements applied under MARAD's 2015 policy for licensing export-specific deepwater ports.[97] As noted previously, LOOP began operations as a crude oil export facility in February 2018.

The MACT floor for a new major source of HAP is the level of control achieved in practice by the best-performing similar source. BWTT has identified exactly one similar source, which does not employ add-on controls. Tankers calling at LOOP, however, are subject to the submerged fill and VOC management plan design standards and work practices under applicable USCG and IMO regulations.

6.3 Identifying all commercially-available technologies (Tier II)

Since a MACT floor of "no control" has been identified, the MACT Guidelines indicate progression to Tier II. At Tier II, all commercially available technologies are identified for similar emissions units, and technically infeasible technologies are eliminated. Any remaining technologies are then ranked according to their HAP reduction performance.

In order to identify commercially available technologies, BWTT considered three main sources of information:

- All control technologies for offshore/near-shore loading operations mentioned in the MACT Y docket or in other government publications (e.g., environmental impact statements), regardless of whether they were considered in setting the MACT floor.
- Control technologies in actual use at any offshore/near-shore loading facility.

---

[96] 65 FR 37814. June 16, 2000. Since Deepwater Port License Amendments are noticed in the *Federal Register*, BWTT performed a full-text search of a commercial library of *Federal Register* notices to arrive at its conclusion that LOOP's license has not been subsequently amended.

[97] 80 FR 26321. May 7, 2015.

- Information obtained through inquiries made to marine engineering firms, control technology manufacturers, and tanker vessel operators.

Three types of commercially available technologies are identified in this section and discussed at length. However, based on its analysis, BWTT does not believe that any of these are technically feasible. Results of the analysis are summarized in Table 6-1, with the columns corresponding to different elements of the technical feasibility determination framework discussed in Section 2.3 (above).

Table 6-1
Summary of Tier II Analysis

Summary of Control Technique	Physical/Operational Constraints?	Demonstrated Performance?	Reasonable?
Recovery system onboard VLCC	No	Yes	No
Vapor recovery pipeline / PLEM	Excessive distance to control device; liquid condensate formation	No	N/A
Recovery system onboard workboat or supply vessel	Potential issues with positioning	No	N/A

6.3.1 Option 1: Recovery system onboard VLCC

The use of a control device located onboard the loaded vessel was identified as an option for mooring buoy-type loading operations:[98]

> *The Coast Guard agrees that these types of facilities present some unique problems, and that having the vapor processing unit on board the vessel is a viable option.*

[98] 55 FR 25407. June 21, 1990.

BWTT has identified three instances where this control technique has been used in a sustained fashion, suggesting that it has demonstrated operational reliability and performance, and that there are no prohibitive physical or operational constraints preventing its application.

As noted previously, the Ellwood Marine Terminal (EMT) conducted barge loading of crude oil in compliance with Santa Barbara APCD Rule 327 using dedicated barges with onboard vapor processing systems. As the following excerpt from the minutes of a 2009 meeting of the California State Lands Commission (concerning the necessity of using of double-hulled barges for transport of crude oil from EMT) indicates, the two controlled barges used during EMT's operating history (*Jovalan* and *Olympic Spirit*) were specially designed vessels, and no comparable vessels of the same type were used at the time.[99]

> *MR. GREIG: The difficulty that we have with the double-hulled barge isn't just the availability of the barge. It's the availability of the vapor recovery unit that goes on the barge. So, while there might be double hulled barges along the Pacific Coast that would work for service in our type of use, they would have to be retrofit and in that a vapor recovery unit that meets the requirements of Santa Barbara County Air Pollution Control District be installed on that barge. The only vapor recovery unit like that that's approved by the district is owned and patented by Public Service Marine, that owns the barge Jovalan, who actually owns the Olympic Spirit and who we contracted with, the developer to build a second or another double-hulled barge, again, with that vapor recovery, so that the time delay is a combination of the availability of the barge, the construction and installation of vapor recovery units and then permitting and getting that confirmed through the APCD that's going to work in that service.*
>
> *...*
>
> *MR. SHEEHY: So they do have not a double-hulled barge with the necessary vapor recovery system? They don't have one that you can use?*
>
> *MR. GREIG: Correct. There's one more barge—*

---

[99] California State Lands Commission. June 1, 2009. Meeting Minutes at 53–55.

MR. SHEEHY: Other than the Jovalan.

MR. GREIG: The Olympic Spirit has that vapor recovery unit, but it's contracted to Tesoro.

A second example of onboard vapor recovery technology it noted for Chevron's El Segundo marine terminal. The facility is subject to SCAQMD Rule 1142, which requires controls of loading and lightering activities in South Coast Waters. Two active SCAQMD Permits to Operate have been located for onboard control devices (carbon adsorption).[100]

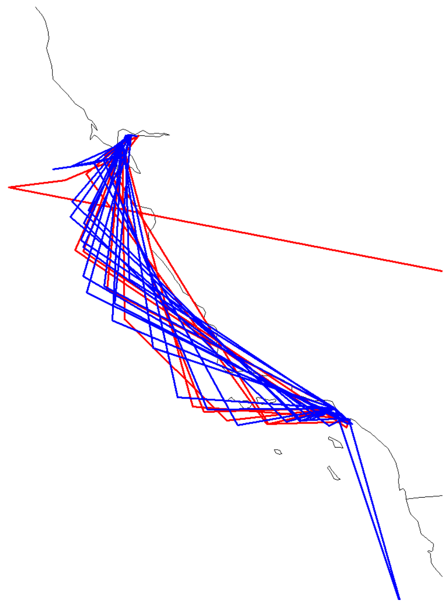
The control devices are associated with two Handymax-sized (340,000 Bbl), Jones Act oil tankers, the *Mississippi Voyager* and the *Florida Voyager*. MARAD data lists the operator of both vessels as Chevron Shipping Co LLC.[101] Figure 7-1 shows two-month trajectories for the two vessels, indicating that their traffic is almost entirely confined to trips between Long Beach or El Segundo (likely loading areas), and either the Chevron Richmond Refinery "Long Wharf," mentioned above, or the Phillips 66 Rodeo Refinery (likely offloading areas). In this case, Chevron affiliates own the terminal in El Segundo and also operate the ships that are loaded at the terminal along relatively fixed itineraries.

[100] SCAQMD Permit to Operate G41614 (July 7, 2016), G28359 (November 13, 2013).

[101] Maritime Administration. United States Flag Privately-Owned Merchant Fleet Report. January 2019.

Figure 6-1

Trajectories for the Florida Voyager and the Mississippi Voyager



A final example of onboard vapor recovery is from shuttle tankers operating in the North Sea.[102] Oil Producers in the Norwegian North Sea are currently subject to a non-methane VOC emission limit of 0.45 kg/m^3 oil loaded (159 lb/MBbl) for transfer operations between an offshore production area such as an F(P)SO and a shuttle tanker. During their service as shuttle tankers,[103] the *Randgrid* and the *Navion Norvegia* employed onboard vapor recovery systems based on carbon adsorption. The control system is visible onboard the *Navion Norvegia*'s deck in one video published by a crew member in 2011.[104]

The installation of control devices onboard shuttle tankers is a reasonable measure for a fleet of vessels subject to a common jurisdiction. Shuttle tankers may be in the Aframax or Suezmax size-class, so scaling up of the technology for VLCC-sized vessels is likely feasible. Individual offshore production sites rely on dedicated fleets of shuttle tankers in cases where produced oil cannot be transported to market via pipeline. Figure 6-2, for example, shows voyage trajectories for the

---

[102] "Developing an effective crude oil vapor recovery system." *Port Technology*. Accessed April 18, 2019 at https://www.porttechnology.org/industry_sectors/developing_an_effective_crude_oil_vapor_recovery_system.

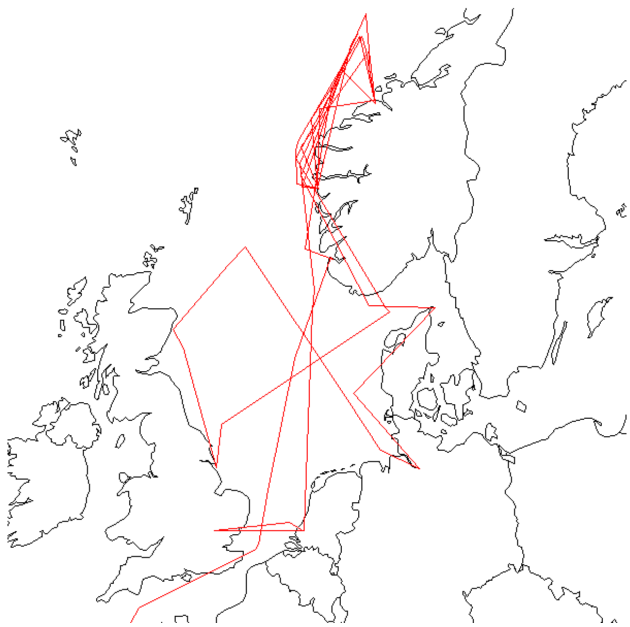
[103] The *Randgrid* has been converted to an FSO and the *Navion Norvegia* to an FPSO.

[104] "Navion Norvegia." Posted by user MrIRA1973. July 26, 2011. Accessed April 18, 2019 at https://www.youtube.com/watch?v=tJvuNoVnZuc.

Randgrid between October 2014 and May 2015.[105] The tanker calls at ports in Norway, Denmark, Germany, Netherlands and UK, repeatedly returning to offshore areas where oil production units are known to operate.

Figure 6-2

Trajectory for the Randgrid



All observed examples of onboard control devices are in cases where an offloading point relies on a dedicated fleet of tankers to transport its product. In such a context, the vessels are controlled by the terminal owner, or specific vessels are contracted for use by the terminal owner. In other words, the use of a dedicated vessel fleet is part of the terminal's business model, and it is not unreasonable to impose specific equipment requirements on such a dedicated fleet. In the case of the proposed deepwater port, however, use of control devices onboard the loaded ship is not reasonable. VLCC's calling at the port are expected to be foreign-flagged vessels owned and operated by companies unaffiliated with BWTT. While equipment requirements applying to crude

[105] The May 2015 voyage was to a shipyard in Singapore, presumably for its eventual conversion to an FSO.

carriers may be a reasonable approach to regulating offshore loading and lightering operations, BWTT believes that such requirements cannot be reasonably imposed on a specific terminal.

6.3.2 Option 2: Vapor recovery pipeline / PLEM

The use of subsea pipelines to route captured loading vapors to a shoreside control device is specifically mentioned in the MACT Y docket. In a July 21, 1993 letter to EPA, Chevron compared the cost of a recently-completed control project for its Richmond, CA "Long Wharf" to a hypothetical project for control of its El Segundo, CA terminal, based on the use of subsea lines.[106] As noted previously, BWTT has determined that such a control system was designed and installed at the Gaviota Interim Marine Terminal (GIMT), and operated for six months. BWTT believes that Chevron, as one of the companies interested in developing oil production from the Point Arguello field, had specific experience with the engineering challenges in developing the system at GIMT. Chevron's 1991–1995 correspondence with EPA and USCG, identifying engineering and regulatory challenges, and advocating for consideration of control systems not involving subsea lines,[107] is best understood in this context.

Although BWTT believes that the system at GIMT was the only vapor recovery pipeline-based control system actually constructed, the concept is also discussed in detail in a Development and Production Plan for the Santa Ynez Unit proposed by Exxon Corporation for a proposed marine terminal in California waters off the coast of Santa Barbara. The system was presented as a solution for controlling vapors generated during loading of tankers at a nearshore SPM (SALM-type), and is described as an "innovative technology".[108] As depicted in Exxon's plan, the vapor recovery line was to be tied to the suction side of an onshore compressor, and therefore to operate at a partial vacuum. Removal of liquid condensate from the vapor recovery line was to be removed by pigging, with a pig launcher and receiver to be located on the sea floor adjacent to the PLEM.[109] The system

---

[106] A-90-44 IV-D-136.

[107] A-90-44 II-E-40, A-90-44 II-D-49, A-90-44 II-D-63, A-90-44 IV-D-136.

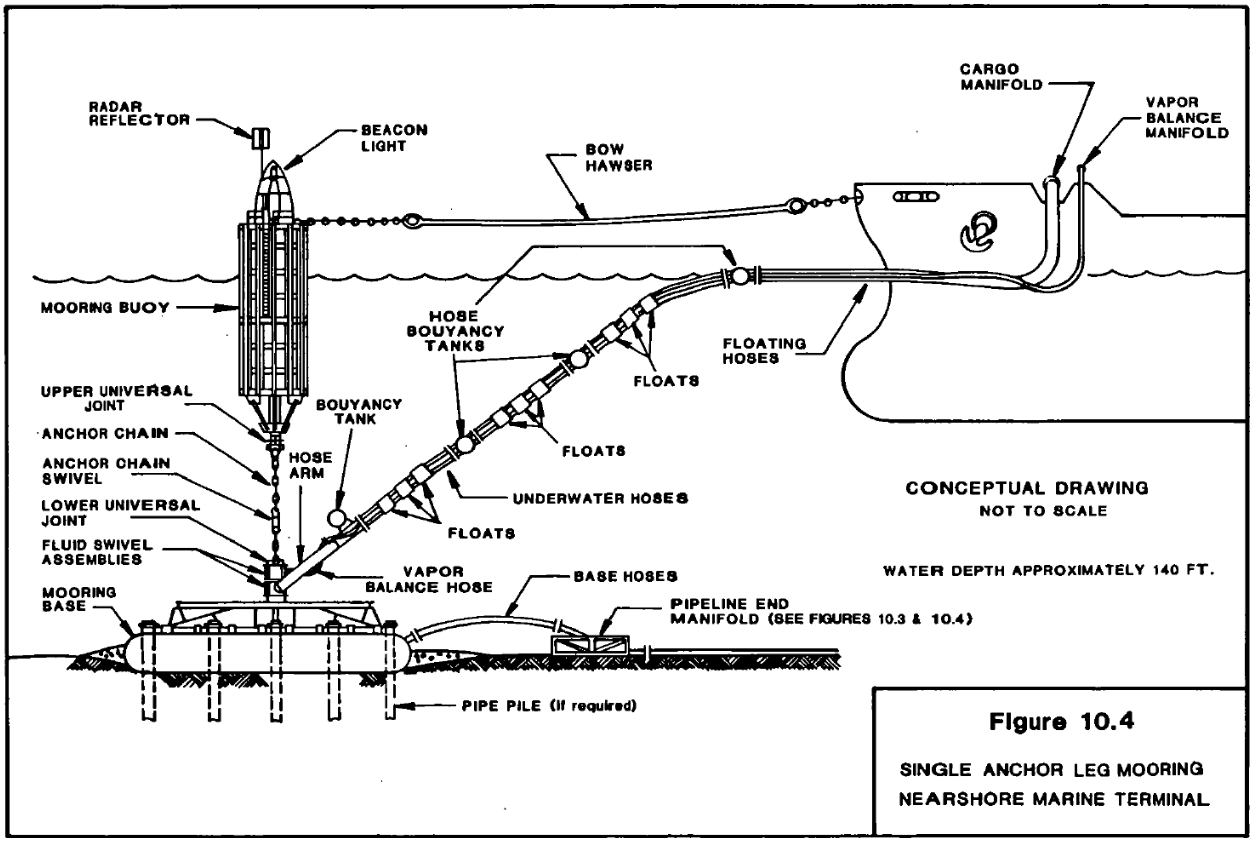
[108] *Memorandum of Agreement II. Development of Santa Ynez Unit, Santa Barbara Channel*. Between the State of California, California State Lands Commission, California Air Resources Board, County of Santa Barbara, Santa Barbara County Air Pollution Control District, and Exxon Company, USA. October 8, 1982.

[109] Interior Department. October 1982. Development and Production Plan: Santa Ynez Unit Development. Exxon Corporation. at X-7–X-12.

was never constructed, and tanker loading from Santa Ynez Unit production was done through the FPSO OS&T.

Figure 6-3

Conceptual Drawing for Vapor Recovery Pipeline with SPM loading[110]



The engineering challenges associated with subsea vapor recovery pipelines are best understood through reference to USCG regulations (33 CFR Part 154, Subpar P) requiring that facility vapor control systems eliminate sources of ignition to the maximum practicable extent, and eliminate potential overpressure and vacuum hazards.[111] While the placement of detonation arresters is one issue that would require a regulatory exemption, BWTT believes that the most serious challenge is designing a means for removing liquid condensate from the vapor collection system.[112] Liquid

[110] *Id*. at X-23.

[111] 33 CFR § 154.2100.

[112] 33 CFR § 154.2100(h).

condensate would be expected in subsea vapor recovery pipelines, its formation being encouraged by temperature differences between the ship's cargo tank and the subsea pipeline, the presence of water vapors (especially in inert gas), and the length of the pipeline. If not regularly removed, liquid condensates could cause excessive back-pressure in the vapor return pipeline, and they could flow as liquid slugs, posing a risk to the vapor recovery blowers.

Liquid condensate could be removed through pigging of the vapor recovery pipeline if the pipelines are installed in pairs (allowing for round-trip travel of the pig), and a pigging system of this type was installed in the GIMT vapor recovery system. However, the rate of condensate formation could be significant, and pigging could be required frequently, one or more times *during* a loading operation (transfer operations would have to be suspended), depending on the level of back pressure experienced at connection to the ship's cargo tank. The high volume of the liquid slug returning with the pig would necessitate a solution for catching and disposing of oily wastewater. BWTT expects that such a system would be prone to operational difficulties, and these difficulties would be prohibitive for a vapor recovery pipeline running 25 miles along the seabed.

BWTT does not believe that a subsea vapor recovery pipeline system has been adequately demonstrated at any facility, and should therefore be rejected as technically infeasible. The system at GIMT was not in operation for a sufficiently long time period to allow for full consideration of its operational reliability. In any case, the distance to shore (3500 feet) was significantly less than in the present case. In order to determine whether any other subsea vapor recovery pipeline systems have been actually installed and operated (besides GIMT), BWTT contacted manufacturers of SPM systems, each of whom has confirmed that they have not commissioned any SPM using a vapor recovery PLEM (correspondence attached in Appendix A).

Finally, BWTT has taken note of a presentation made by a John Zink Hamworthy Combustion ("John Zink") engineer[113] which apparently depicts the recovery of crude oil vapors from a SPM-type loading facility using a vapor recovery pipeline and PLEM. Recent correspondence with John Zink confirms that the technology has never been applied in practice (correspondence attached in Appendix A).

---

[113] Puglisi, Marco. 2012. Vapor Control on Crude Oil Loading. Accessed April 18, 2019 at https://www.platts.com/IM.Platts.Content/ProductsServices/ConferenceandEvents/2012/pc379/presentations/d2_4_Marco_Puglisi.pdf.

6.3.3 Option 3 Recovery system onboard workboat / PSV

A third possibility is the use of a control device mounted onboard a workboat. Such a control technique is mentioned in a June 25, 1992, presentation made by Chevron staff to EPA. The presentation describes a proposal by Public Service Marine, Inc. (PSMI), for a workboat having a 12,500 Bbl/hr vapor processing capacity.[114] As noted above, PSMI was the owner of the two barges (*Jovalan* and *Olympic Spirit*) used for controlled loading at EMT.

The workboat concept was presented to EPA as a possible strategy for Chevron's Estero Bay marine terminal to achieve compliance with what is currently codified as San Luis Obispo County APCD ("SLO APCD") Rule 427. While the rule was under consideration in 1991, it was not promulgated until 1995, and the compliance date was not until April 26, 1997. The terminal ceased operations no later than mid-1999 and no workboat was actually deployed at the Estero Bay terminal. For loading operations conducted between 1997 and 1999, compliance with Rule 427 was achieved through the use of emissions offsets.[115]

BWTT is aware of at least one workboat in actual use for the processing of vapors during marine loading operations.[116] Foss Maritime is the owner of the *San Pedro* (reported as calling at El Segundo), as well as three additional barges (*FDH 35-3, FDH 35-4,* and *FDH 35-5*) equipped with onboard carbon adsorption units. Foss Maritime holds operating permits issued by SCAQMD which restrict the loading rate of each barge to 8,000–12,000 Bbl/hr and restrict cargoes handled to petroleum liquids having a maximum vapor pressure of 0.75 psia at loading temperature.[117]

The system is described as follows by a Foss Maritime employee:[118]

---

[114] A-90-44 II-E-40.

[115] SLO APCD. July 3, 1997. Engineering Evaluation: Emission Banking and Permit to Operate. Permits 2147 etc. Chevron Products Company et al.

SLO APCD. April 30, 1998. Permit to Operate C-1232-A-1. Issued to Chevron Pipeline Company.

[116] Marcon International, Inc. December 2004. *Tank Barge Market Report*. Accessed April 18, 2019 at http://www.marcon.com/library/market_reports/2004/TB/TB1204.pdf. At 9.

[117] SCAQMD Permits to Operate R-G2640 (May 12, 2009), G25415 (June 28, 2013), G25416 (June 28, 2013), and G25421 (June 28, 2013).

[118] "Scrubbing VOCs from bunkers helps clean the air." March 23, 2011. *WorkBoat*. Accessed April 18, 2019 at https://www.workboat.com/archive/scrubbing-vocs-from-bunkers-helps-clean-the-air/.

> *"The San Pedro barge is the only barge in the world that we know of that does third-party vapor processing," said Costin. "We had a customer come to us and since we already had our operating permits under the South Coast Air Quality Management District, it was an easy fit to convert the barge to be able to take what we call 'third-party vapors.' It's an ideal platform that we can work offshore because it's outfitted with special mooring and surge gear. As the ship is loading cargo from a terminal or other source, we're connected on the outboard side to their vapor line and they push their vapors down through our system. The barge can process up to 15,000 barrels an hour."*

BWTT believes that workboat-type technology could conceivably be applied to the offshore loading of crude oil, but believes that there are significant differences between the bunker loading operations controlled by the Foss Maritime barges and the proposed crude oil export terminal. The three factors are positioning of the workboat, environmental conditions offshore, and the necessary capacity of the recovery system. Since tankers at El Segundo are spread-moored (and therefore held in a fixed position), a workboat can be moored in close proximity to the loaded tanker. Mooring of a service vessel in proximity to a VLCC being loaded at an SPM would require modification of the safety zone and design of the support vessel with a dynamic positioning system to maintain a fixed position with respect to the VLCC. Environmental conditions would present a challenge for achieving continuous reduction of HAP emissions, since the service vessel would have to depart from its position in the event of strong currents or winds. Finally, the size of the vessel and onboard control equipment would have to be scaled up to accommodate a significantly higher volume of vapors: the higher vapor pressure, loading rate, and presence of inert gas in the loading vapors imply a vapor flow rate two orders of magnitude greater than would be expected for the Foss Maritime barges.

BWTT finds that the workboat concept is not unreasonable in principle, but should be treated as technically infeasible because no similar system has been demonstrated in practice.

6.4 Conclusion

This section has presented the Tier I and Tier II portions of the case-by-case MACT analysis. BWTT has found exactly one similar source that is currently in operation (LOOP). Since LOOP does not use add-on controls for loading, a MACT floor finding of "no control" is appropriate, indicating progression to Tier II. In its Tier II analysis, BWTT has attempted to identify all extant technologies that could potentially be applied to offshore loading operations of the type proposed. Three classes of technology have been identified. One technology (control device onboard tanker) has been demonstrated in practice for operations of similar scale, but is rejected as unreasonable since it would require BWTT to control the vessels calling at its facility. The other two technologies (vapor recovery pipeline and workboat) are rejected as unreasonable because they have not been adequately demonstrated in practice for offshore crude oil loading operations.

Section 7
Beyond the Floor Analysis

7.1 Introduction

The "beyond the floor" analysis, corresponding to Tier III in EPA's MACT Guidelines guidance, must consider all "available information" (40 CFR § 63.41) and must also consider any relevant emission standards that have been proposed by the EPA administrator. MACT may consist of an operational or work practice standard if it is not feasible to prescribe or enforce an emission limitation.

In the present section, BWTT considers any possible beyond the floor reductions that should be considered in making a MACT Finding. Beyond the floor considerations include the use of innovative technologies or technology transfer. As noted previously, MACT Guidelines indicate that beyond the floor technologies should be subject to technical feasibility and cost considerations, and may be appropriate especially in cases where emissions pose a high risk or involve highly toxic pollutants (e.g., chromium).

BWTT identifies one possible technology transfer-based control technique in this section. However, it would fundamentally alter the scope of the project, and would likely have an unreasonable incremental cost-effectiveness. Additionally, BWTT believes that considerations of risk should not play a role in favoring beyond the floor reductions due to the remote location of the proposed project. Therefore, BWTT does not believe that it is appropriate to consider any beyond the floor reductions.

7.2 Technology Transfer

Lavagna et al[119] describe a system for tandem offloading of Liquefied Natural Gas (LNG) from an LNG FPSO to an LNG carrier. While the focus of the presentation is on the design of the necessary cryogenic hose used to accomplish the transfer operation, the system includes the use of a cryogenic line for return of cold boil-off gas to the FPSO for flaring:

---

[119] Lavagna, Damien, Le Touzé, Laurent, and Fournier, Jean Robert. 2011. "LNG Tandem Offloading — A Qualified Technology Now Ready for FLNG Projects." Presentation from the Offshore Technology Conference held in Rio de Janeiro, Brazil, 4–6 October 2011.

A three offloading lines configuration is required to achieve a LNG flow rate similar to a land based terminal and handle vapor back to the FLNG. The LNG transfer is carried out with two 18" inner diameter COOL™ hose sections allowing up to 10,000 m^3/h total flow rate. An identical 18" extra vapor return line is used to handle the cold Boil-Off Gas (BOG) resulting from the heat transferred to the LNG during cargo operations. The offloading line configuration is designed to accommodate severe environmental configurations.[120]

This report illustrates the possibility of a vapor return system that would not be subject to the same liquid condensate formation issues as a subsea vapor return pipeline. The tandem loading configuration is illustrated in 7-1 for an FSO moored offshore of Angola, offloading to a shuttle tanker. As discussed in the preceding Tier II analysis, BWTT believes that it is not unreasonable to equip a tanker with a control device if it is under the control of the terminal operator. Additionally, since FSO's and FPSO's are frequently built by converting existing Aframax or Suezmax tankers, they would be appropriately sized for controlling vapor flows of the magnitude that could be expected during an 85,000 Bbl/hr crude oil transfer operation.

BWTT has additionally determined that the FPSO "OS&T," which formerly operated in federal waters off the coast of Santa Barbara (cf. discussion above) conducted controlled offloading operations via tandem loading onto the Handymax-size shuttle tanker *Exxon Jamestown*, which was specially equipped for vapor balance operations.[121]

Two photographs depicting tandem loading operations are depicted in Figure 7-1. Shown are an external turret-moored FSO moored offshore of Angola as well as the *Overseas Tampa* receiving cargo from *FPSO Turritella* in the Gulf of Mexico. As discussed in the preceding Tier II analysis, BWTT believes that it is not unreasonable to equip a tanker with a control device if it is under the control of the terminal operator. Additionally, since FSO's and FPSO's are frequently built by converting existing

[120] Id. at 3.

[121] Interior Department. October 1982. Development and Production Plan: Santa Ynez Unit Development. Exxon Corporation. At VIII-59, IX-11.

Interior Department. September 20, 1985. Approval re: Santa Ynez Unit Development and Production Plan.

Brennan, JR. "Screw pumps move heavy California offshore crude effectively. *Oil & Gas Journal* 92:60–62.

Aframax or Suezmax tankers, they would be appropriately sized for controlling vapor flows of the magnitude that could be expected during an 85,000 Bbl/hr crude oil transfer operation.

Figure 7-1

Tandem Offloading from F(P)SO to Shuttle Tanker[122,123]

[122] Lanquetin, B. 2005. “More than 30 Years’ Experience with F(P)SO’s and Offloading Techniques.” Paper presented at the International Petroleum Technology Conference in Doha, Qatar, 21–23 November 2005.

[123] Shell Upstream Americas. January 26, 2017. *Notice to Airmen: FPSO Turritella Offload Operations Alert*. Accessed April 29, 2019 at http://www.avnotice.com/archive/160_1563.pdf.

Thus, existing technology from related fields could conceivably be combined to arrive at a control solution for an offshore crude oil export terminal. In the case of the proposed project, however, such a solution would entail replacement of the proposed SPM with a permanently moored FSO. While the cost of purchasing, retrofitting, and operating a Suezmax tanker as an FSO would be significantly higher than BWTT's intended SPM system, BWTT believes that the identified technology transfer solution should be rejected because it would amount to "redefining the source." It should be rejected for the same reason as onboard control systems were rejected as an option in the Tier II analysis.

7.3 Proposed Emission Standards

The beyond the floor analysis includes a review of "*a relevant proposed regulation, including all supporting information*."[124] BWTT understands that this provision was intended primarily to apply to major sources of HAP that were to be constructed (or reconstructed) during the time when EPA was in the process of proposing and promulgating regulations for the initial source of NESHAP source categories.[125] BWTT does not believe that there are any proposed regulations which can inform the Tier III analysis.

7.4 Consideration of Risk

BWTT believes an important consideration in not imposing beyond the floor reductions is the remote nature of the emissions-generating activity. Emissions of crude oil vapors will take place eighteen miles from any land-based receptor, and the likelihood of public exposure to HAP emissions is very low.

BWTT believes that it is also relevant to note that the proposed facility would tend to displace reverse lightering operations (i.e., uncontrolled, ship-to-ship transfers) that currently take place in the Gulf of Mexico. Therefore, if consideration is given to existing air quality in the Gulf of Mexico, the project is not expected to result in significant negative impacts.

Risk-based considerations are discussed in more detail in a concurrently-filed Environmental Impact Statement for the project.

---

[124] 40 CFR § 63.41.

[125] Cf. CAA § 112(j)(6).

Section 8
Case-by-Case MACT Determination

Based on the analysis presented in Sections 5–7, BWTT believes that the emission standards in MACT Y do not apply to the proposed deepwater port, that the MACT floor consists of no add-on controls, and that no add-on controls should be required to satisfy “beyond the floor” level controls.

As MACT for the proposed, facility, BWTT proposes that MACT consist of a work practice involving two elements:

- Bottom fill the discharge point of a cargo tank filling line should be no higher above the bottom of the cargo tank or sump than 10 cm (approx. 4 in.) or the radius of the filling line, whichever is greater (46 CFR § 153.282).

- VOC Management the terminal operator shall not permit any vessel to be loaded unless it possesses and implements a VOC management plan consistent with the requirements specified in 40 CFR § 1043.100(b)(1), Regulation 15.6.

Actual provisions of a suggested Notice of MACT Approval (NOMA), including recordkeeping, reporting, monitoring and compliance provisions, are contained in Section 9. In addition to the work practice standards identified above, BWTT proposes monitoring and recordkeeping requirements to ensure that total HAP emissions from the facility do not exceed the potential to emit specified in Section 4 of the application.

Section 9
Suggested NOMA

Notice of MACT Approval

40 CFR Part 63, Subpart C

Maximum Achievable Control Technology Emission Limitation for Constructed and Reconstructed Sources under Section 112(g)

This notice establishes practicable, enforceable maximum achievable control technology emission limitations, work practice standards and other requirements for Blue Water Texas Terminal LLC ("BWTT") for the MACT-affected emission units located at the BWTT Deepwater Port. The work practice standards and requirements set forth in this document are enforceable on **[effective date of notice].**

A. Major Source Information

1. Mailing address of owner or operator:

   2331 CityWest Blvd, Houston, Texas 77042

2. Location of major source:

   Gulf of Mexico: 27° 53′ 21.70″ N, 96°39′ 4.16″ W ("SPM 1"); and 27° 54′ 9.28″ N, 96° 37′ 41.23″ W ("SPM 2")

3. Source category or subcategory for major source:

   Deepwater port crude oil export terminal

4. Type of construction or reconstruction:

   Construction of new affected facility

5. Project description:

BWTT proposes to construct a deepwater port for export of crude oil via two Single Point Mooring (SPM) systems. The SPM's will be located at 27° 53′ 21.70″ N, 96°39′ 4.16″ W and at 27° 54′ 9.28″ N, 96° 37′ 41.23″ W, in BOEM lease block TX4, subdivisions 698 and 699 (see Appendix A). The facility will be approximately 18 statute miles from Matagorda Island at its nearest point and 26 statute miles from the entrance to Port Aransas. At the location of the deepwater port, the water depth is approximately 89 feet, which provides sufficient under keel clearance for a fully laden oil tanker in the Very Large Crude Carrier (VLCC) size range.

Loading of vessels is accomplished through two single point mooring (SPM) systems, each consisting of a pipeline end manifold (PLEM), a catenary anchor leg mooring (CALM) buoy, and hose strings. During loading operations, crude oil is pumped from the onshore valve and pipeline infrastructure to the deepwater port through two 30" offshore pipelines. The pipelines run along the seabed and terminate at a PLEM which is also affixed to the seabed. Each CALM mooring buoy is anchored by several catenary chains extending radially outward and down to the seabed. The buoy moves up and down with the tide and waves, and floats above the PLEM. The CALM buoy is partially submerged and its upper part is able to freely rotate about its base. One or more under-buoy hoses connect to the submerged portion of the CALM buoy and transfer crude oil from the PLEM to the CALM buoy. A floating hose string connects the CALM buoy to a tanker vessel in order to deliver crude oil.

6. Equipment List

   The following devices are subject to this notice:

   (a) Catenary Anchor Leg Mooring buoy located at 27° 53′ 21.70″ N, 96°39′ 4.16″ W, including associated PLEM, mooring hawser, floating hose, and under buoy hoses (Emission Point Number SPM1).
   (b) Catenary Anchor Leg Mooring buoy located at 27° 54′ 9.28″ N, 96° 37′ 41.23″ W, including associated PLEM, mooring hawser, floating hose, and under buoy hoses (Emission Point Number SPM2).

7. Anticipated commencement date for construction or reconstruction:

   March 1, 2020

8. Anticipated start-up date of construction or reconstruction:

   July 1, 2021

9. List of the hazardous air pollutants emitted by MACT-affected emission units:

   Crude oil vapors (which may contain Benzene, Ethyl benzene, Hexane, Naphthalene, Toluene, 2,2,4-Trimethylpentane, o-Xylene, m-Xylene, and p-Xylene).

B. MACT Emission Limitation

1. Emissions of HAP shall not exceed 875 tons per year during any rolling 12-month period.
2. Liquids loaded into the cargo tanks of transport vessels shall be limited to crude oil, pipeline interface (transmix), and water. For purposes of this notice, "crude oil" shall include lease condensate.
3. The true vapor pressure of any loaded crude oil shall not exceed 11.0 psia.
4. The total volume of crude oil loaded shall not exceed 384,000,000 Barrels (61,049,285 m^3) during any rolling 12-month period.
5. The above stated owner or operator shall not permit any vessel to be loaded unless it complies with the equipment design specifications of 46 CFR § 153.282.
6. The above stated owner or operator shall not permit any vessel to be loaded unless it possesses and implements a VOC management plan consistent with the requirements specified in 40 CFR § 1043.100(b)(1), Regulation 15.6.

C. Monitoring Requirements

1. The above stated owner or operator shall determine and document the HAP content of the hydrocarbon vapors in equilibrium with the liquid phase of each grade of crude oil loaded using EPA Test Method 18 (40 CFR Part 60, Appendix A-6). Crude oil samples shall be taken from the final storage location prior to delivery to the loading facility. Sampling shall be conducted on an annual basis. For purposes of this provision, two samples of crude oil correspond to different grades if they are produced from distinct regions identified in the U.S. Energy Information Administration Drilling Productivity Report.
2. The above stated owner or operator shall, on a monthly basis, calculate the estimated HAP emissions from crude oil loading operations during the preceding 12-month period. Emissions estimates and emission factors shall be based on test data, or if test data is not available, shall be based on measurement or estimating techniques generally accepted in industry practice for operating conditions at the source.

D. Reporting and Recordkeeping Requirements

1. The above stated owner or operator shall notify EPA Region 6 in writing or by electronic mail of the following activities. Such notifications shall be delivered or postmarked within 30 calendar days after the date the activity takes place:

   (a) the actual date construction is commenced;
   (b) the actual date construction is completed; and
   (c) the actual date of startup of the source.

2. Records containing the information and data sufficient to demonstrate compliance with the provisions of this approval shall be maintained at an office having day-to-day operational control of the site. Such records shall be maintained for at least five years following the date the information or data is obtained.
3. The above stated owner or operator shall maintain a file which specifies, for each crude oil loading operation, the following information:

   (a) The volume of crude oil loaded;
   (b) The true vapor pressure of the crude oil loaded;
   (c) The date and time of commencement and completion of the loading operation;
   (d) The estimated quantity of HAP emissions resulting from the loading operation;
   (e) The identifier of the mooring buoy at which loading takes place (i.e., SPM1 or SPM2);
   (f) The IMO registry number corresponding to the loaded vessel;

E. Other Requirements

1. The above stated owner or operator shall comply with the startup, shutdown and malfunction (SSM) plan requirements specified at 40 CFR § 63.6(e).
2. At all times, including periods of startup, shutdown, and maintenance, the above stated owner or operator shall, to the extent practicable, maintain and operate the facility including any associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the EPA, which may include, but is not limited to, monitoring results, review of operating maintenance procedures and inspection of the facility.
3. The requirements of this notice shall be administratively incorporated into the facility's Title V operating permit (40 CFR Part 71) upon issuance of such operating permit.
4. Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18

months or more, or if construction is not completed within a reasonable time. The Administrator may extend the 18-month period upon a satisfactory showing that an extension is justified.

5. EPA authorized representatives, upon the presentation of credentials, shall be permitted to undertake the following actions:
   - (a) Enter the premises where the facility is located or where any records are required to be kept under the terms and conditions of this notice;
   - (b) During normal business hours, have access to and make copies of any records required to be kept under the terms and conditions of this notice;
   - (c) Inspect any equipment, operation, or method subject to requirements in this notice; and
   - (d) Sample materials and emissions from the sources.
6. In the event of any changes in control or ownership of the facilities to be constructed, this notice shall be binding on all subsequent owners and operators. The above stated owner or operator shall notify the succeeding owner and operator of the existence of this notice and its conditions by letter; and a copy of the letter shall be forwarded to EPA Region 6 within thirty days of its signature.
7. The provisions of this notice are severable, and, if any provision of this notice is held invalid, the remainder of this notice shall not be affected.

F. Compliance Certifications

1. The above stated owner or operator shall certify compliance with the terms and conditions of this notice according to the provisions specified at 40 CFR § 63.9(h). All compliance and enforcement correspondence required by this notice shall be delivered to the following address:

   Compliance and Enforcement Division
   EPA Region 6
   1445 Ross Avenue (6EN)
   Dallas, TX 75202

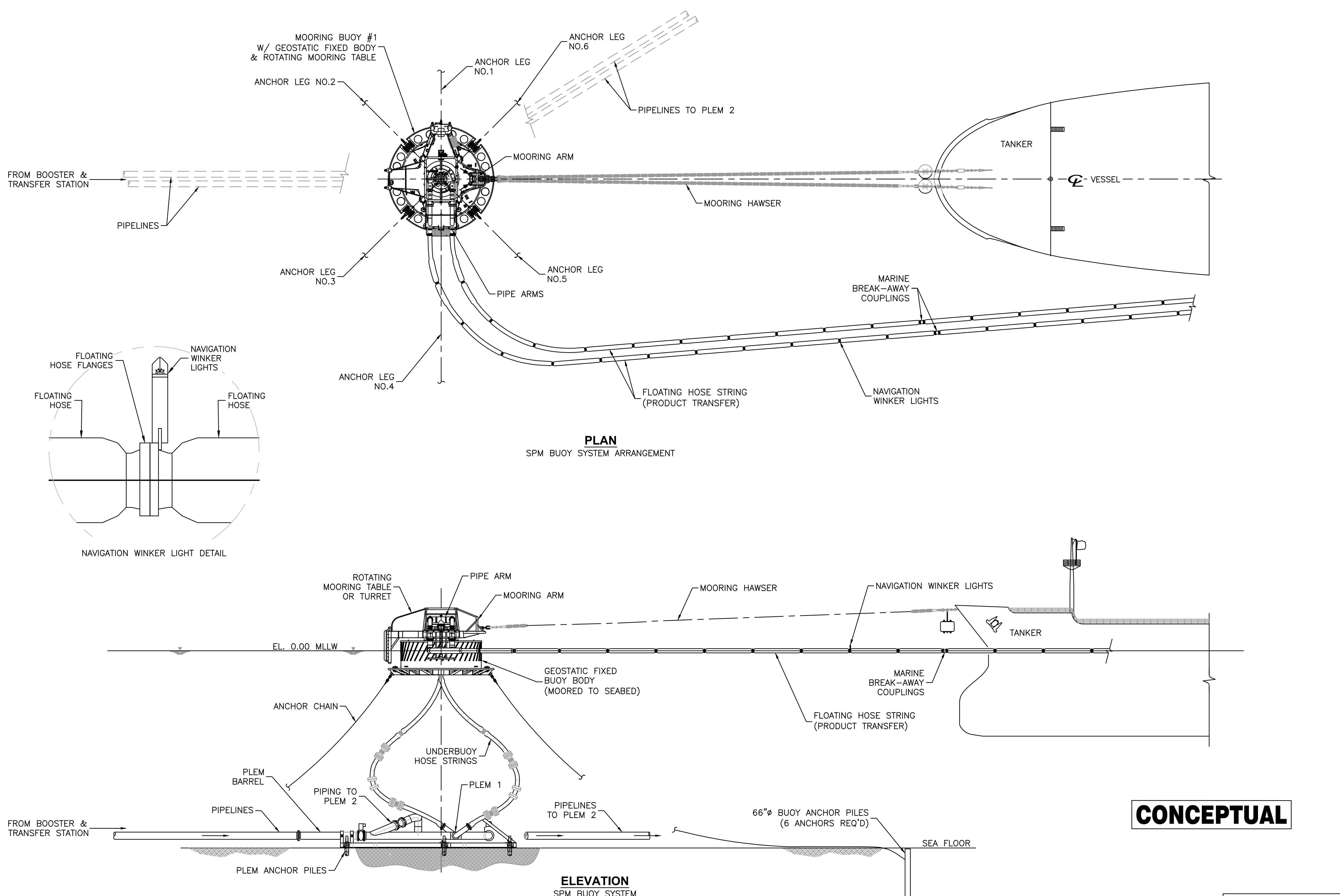
Appendix A

Facility Layout

Surrounding Area

Correspondence with SPM Manufacturers

Correspondence with John Zink



CONCEPTUAL

CONFIDENTIAL BUSINESS PROPRIETARY INFORMATION EXEMPT FROM FOIA

NO.	DESCRIPTION	DATE	APPR
A	ISSUED FOR REVIEW	MM/DD/YY	-

ISSUED FOR REVIEW

PHILLIPS 66

SEAL

BLUEWATER TERMINAL LLC

CLIENT

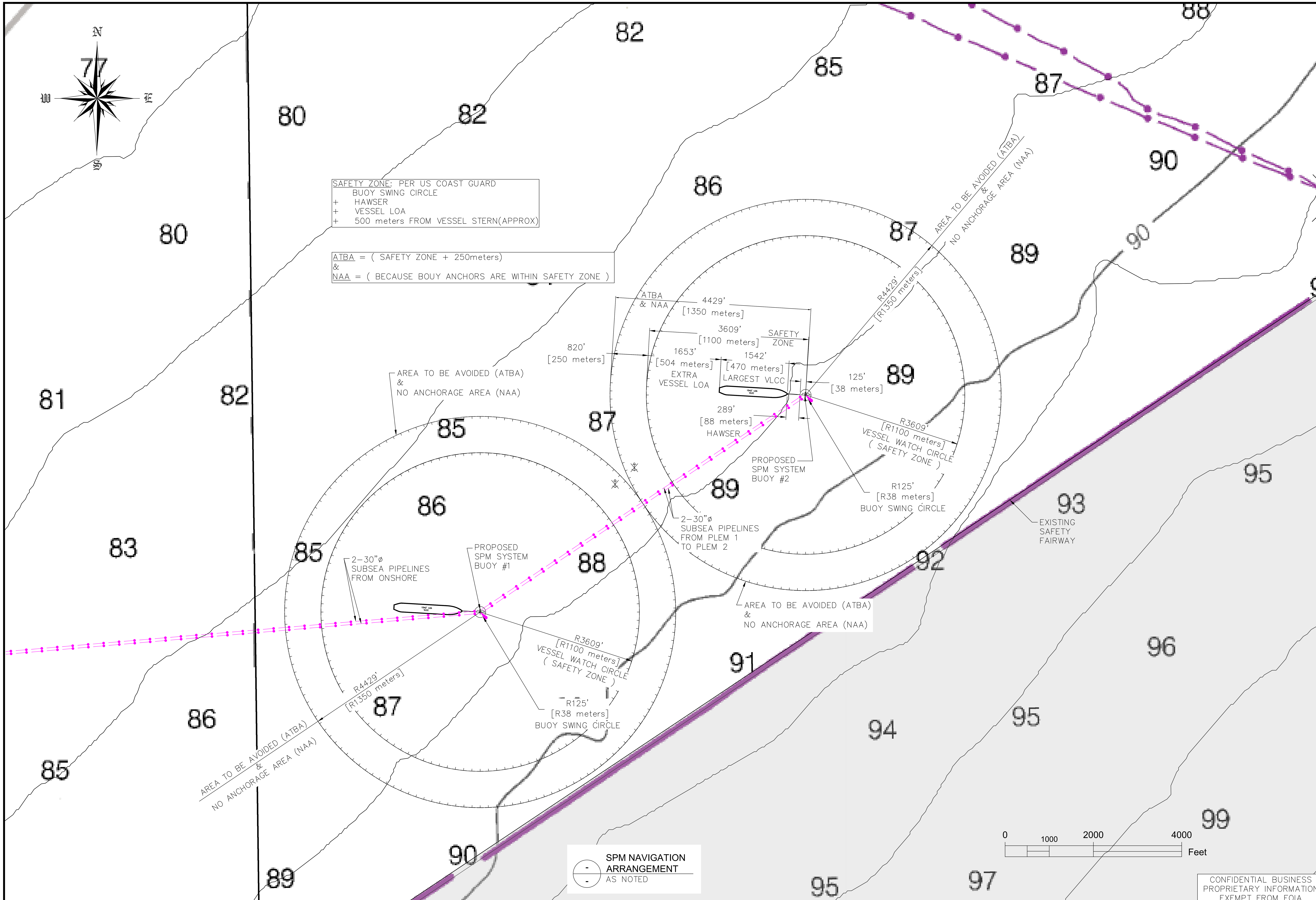
BLUEWATER SPM PROJECT
ARANSAS PASS, TEXAS

SPM BUOY 1 SYSTEM ARRANGEMENT

LLOYD ENGINEERING, INC
STATE OF TEXAS, USA LICENSE NO. F-002846

DESIGN BY:	JSL
DRAWN BY:	RC
DATE:	OCT 2018
SCALE:	AS NOTED @ 22"X34"
SHEET:	12 OF 15
DRAWING NO:	12
REV. ----	

FILE NAME: L:\LEI Projects\P66\SPM Harbor Island\6.0 Drawings\Conceptual\12 SPM BUOY 1 SYSTEM ARRANGEMENT.dwg PLOTTED: 2/28/2019 2:37:36 PM USER: RALF CABALLERO



CONFIDENTIAL BUSINESS
PROPRIETARY INFORMATION
EXEMPT FROM FOIA

NO.	DESCRIPTION	DATE	APPR
A	ISSUED FOR PERMIT	-	-

ISSUED FOR PERMIT

PHILLIPS 66

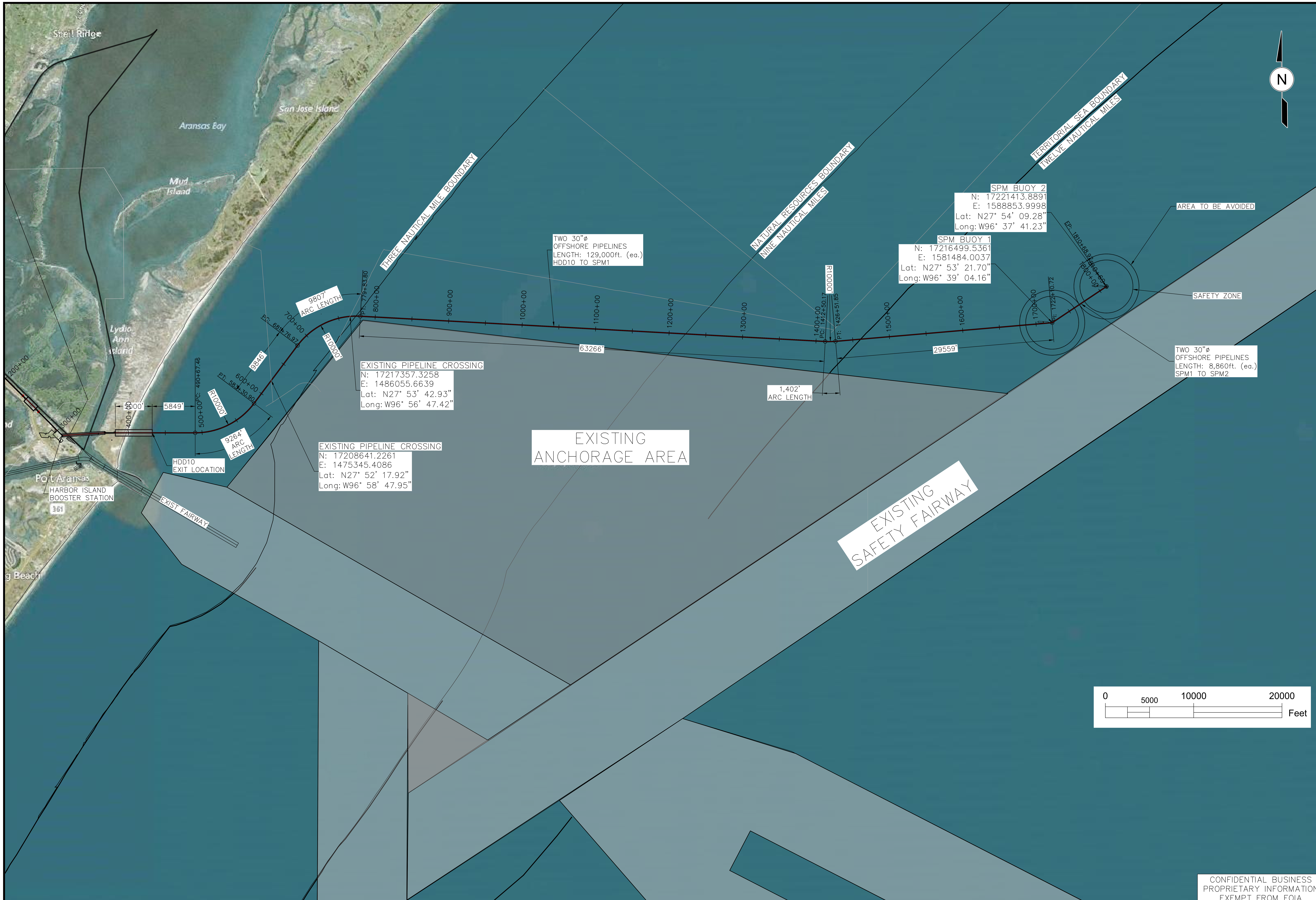
BLUEWATER
TEXAS
TERMINAL, LLC

BLUEWATER SPM PROJECT
ARANSAS PASS, TEXAS

DEEPWATER PORT NAVIGATION ARRANGEMENT

LLOYD ENGINEERING, INC
STATE OF TEXAS, USA
LICENSE NO. F-002846

DESIGN BY:	JSL
DRAWN BY:	RC
DATE:	MAY 2018
SCALE:	AS NOTED @ 22"X34"
SHEET:	6 OF 22
DRAWING NO:	6
REV. A	



ISSUED FOR PERMIT

NO.	DESCRIPTION	DATE	APPR
A	ISSUED FOR PERMIT	-	-

PHILLIPS 66

BLUEWATER TEXAS TERMINAL, LLC

BLUEWATER SPM PROJECT
ARANSAS PASS, TEXAS

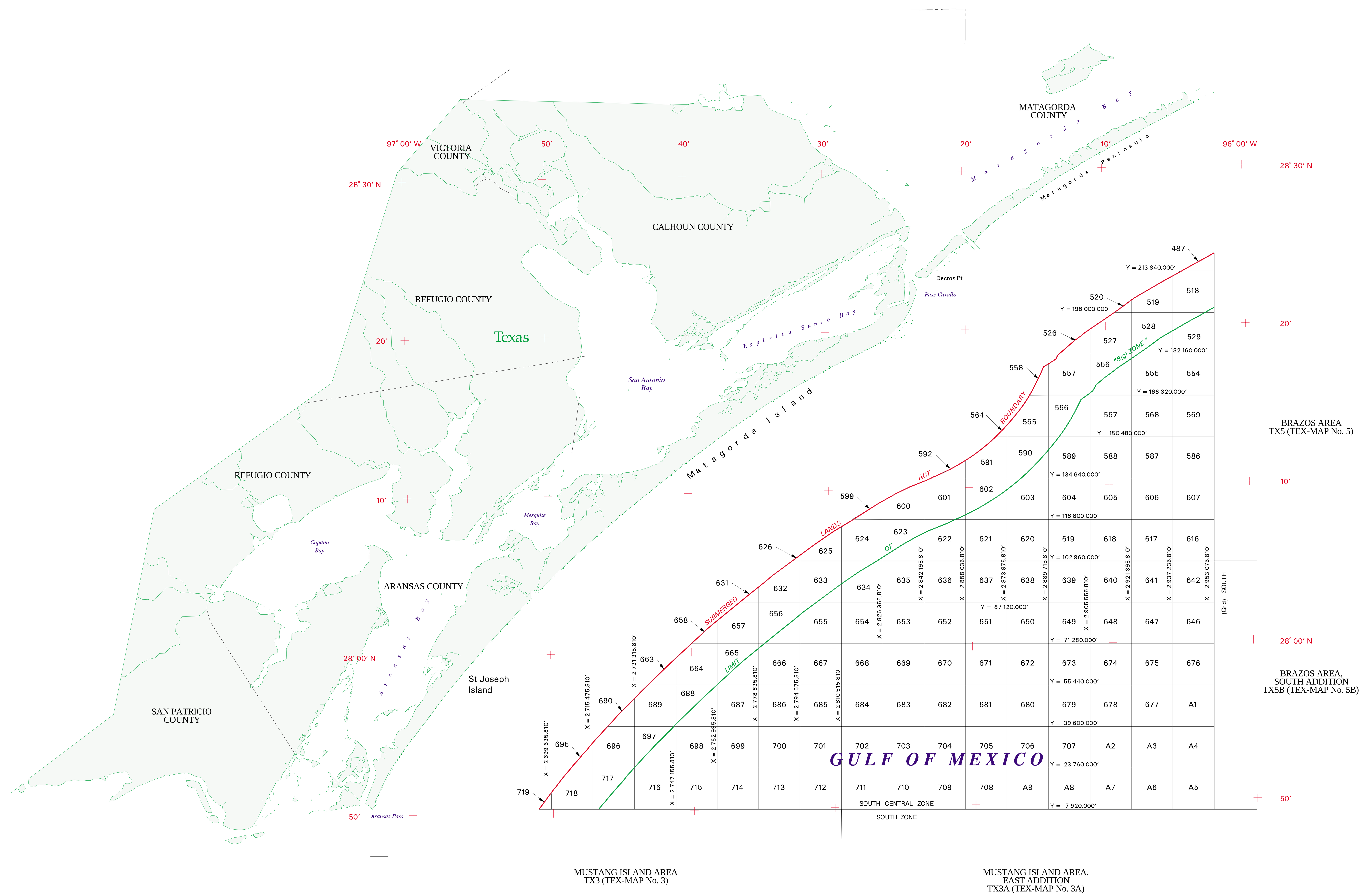
OFFSHORE LAYOUT

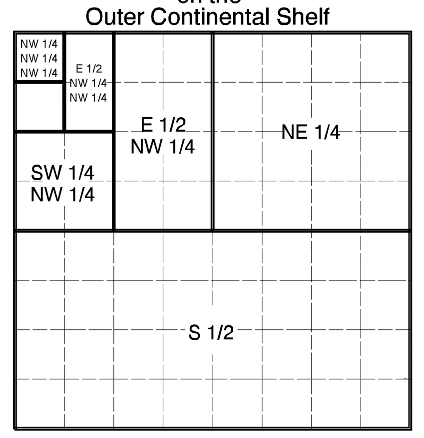
LLOYD ENGINEERING, INC
STATE OF TEXAS, USA LICENSE NO. F-002846

DESIGN BY:	JSL
DRAWN BY:	RC
DATE:	MAY 2018
SCALE:	AS NOTED @ 22"X34"
SHEET:	4 OF 22
DRAWING NO:	4
REV. A	

CONFIDENTIAL BUSINESS PROPRIETARY INFORMATION EXEMPT FROM FOIA

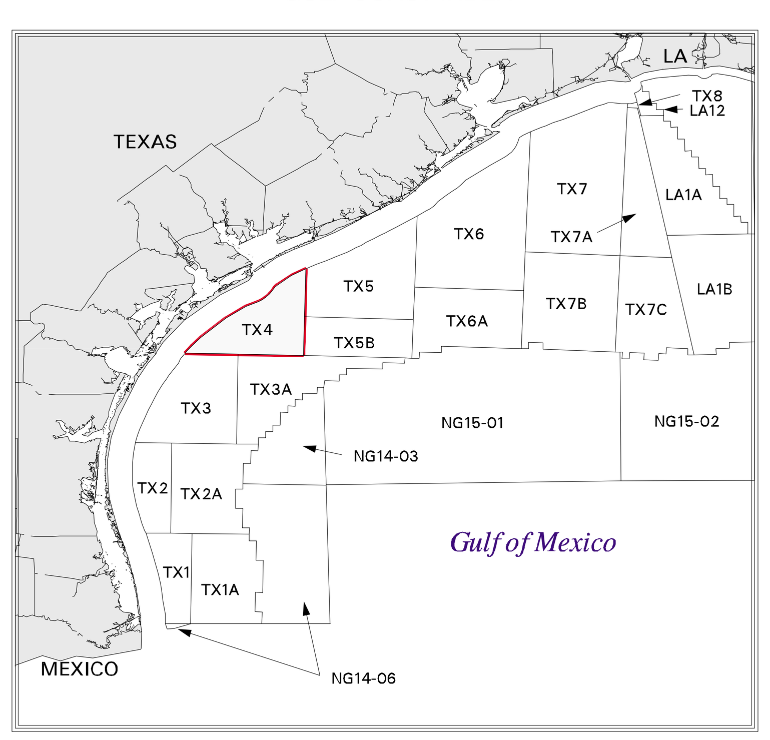
FILE NAME: I:\ei projects\P66\spm harbor island\6.0 drawings\conceptual\4 OFFSHORE LAYOUT.dwg PLOTTED: 5/10/2019 2:22:23 PM USER: RALF CABALLERO





Typical method of subdivision of the regular blocks, each subdivision being an aliquot part of the total, based on midpoint subdivision throughout.

TEXAS GULF COAST INDEX



All blocks are based on the Texas (Lambert) Plane Coordinate System, South Central Zone, with X origin = 2,000,000' at 99° 00' W and Y origin = 0.00' at 27° 50' N.

Regular blocks are 15,840 feet on a side and contain 5,760 acres.

Onshore planimetric base compilation is from USGS 1:100 000 Digital Line Graph (DLG) Files.

This revised map supersedes leasing map MATAGORDA ISLAND AREA, TEX-MAP No. 4, approved 16-JUL-1954, and TX4 revised 01-SEP-1999.

The Submerged Lands Act Boundary and Limit of "8(g) Zone" lines depicted hereon reflect the official federal position for Submerged Lands Act and OCS Lands Act purposes. The areas of the fractional blocks abutting these lines have been determined and are as depicted on the Supplemental Official OCS Block Diagrams (SOBD's). Consult the SOBD's for official descriptions and approval dates.

Copies of these diagrams and other information may be obtained at the appropriate MMS OCS Region.

UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

OUTER CONTINENTAL SHELF LEASING MAP

TEXAS

NORTH AMERICAN DATUM OF 1927

Scale 1:250 000

This diagram is prepared in accordance with 30 CFR 256.8

For the Director

Chief, Leasing Division, Mapping and Boundary Branch

Denver, Colorado Date 01-NOV-2000

Revised

Date: Monday, 07 May 2018

Lloyd Engineering, Inc.
6565 West Loop South, Suite 708
Houston, TX 77401

Attention: Stan Lloyd – President

Subject: ABS Rules for Building and Classing Single Point Moorings – 2014 (updated March 2018)

Dear Sir,

Relative to your email dated 6 May 2018 inquiring whether ABS Rules for Building and Classing Single Point Moorings contain requirements or provisions for vapor control systems on SPM's, please be advised as follows:

The ABS SPM Rules contain requirements for fluid transfer systems on Single Point Moorings. The fluid transfer system includes the pipeline end manifold (PLEM), riser, product swivels and floating hoses. These Rules do not include requirements for vapor control systems.

We have also checked our records of Single Point Moorings recently classed by ABS and have verified that none have been fitted with vapor control systems

If you have any questions, please do not hesitate to contact the undersigned.

Regards,

Bret Montaruli
Vice President and Chief Engineer

ABS Plaza, 16855 Northchase Drive | Houston, TX 77060 USA
TEL: 1-281-877-6000 | FAX: 1-281-877-5976 | Email: ABS-WorldHQ@eagle.org | www.eagle.org

From: [redacted] Terry <[redacted]@johnzink.com>
Sent: Friday, April 26, 2019 4:52 PM
To: Dave, Chaitali R <[redacted]@p66.com>
Cc: [redacted] <[redacted]@johnzink.com>
Subject: [EXTERNAL]RE: Confidential - Crude Oil Loading/Unloading Control Equipment

Chaitali –

We have not implemented a vapor combustion solution for a single point mooring project, though we have performed an engineering study on this type of application and placed considerable engineering horsepower behind it. I am not personally aware of any SPM vapor combustion systems in service for a loading application in US waters.

The end control device in such an instance, along with a vapor blower package suitable for transferring the vapors generated from such an operation, could be placed on an offshore platform or onshore depending upon the economics of each scenario. Perhaps a more complicating factor is what the US Coast Guard will allow in terms of the distance from the vessel to a Dock Safety Unit which contains the equipment necessary to assure a safe loading operation. Generally speaking, the SPM does not provide adequate space to install a DSU; however, the USCG prefers to see the DSU located as close to the vessel as reasonably possible.

I have been at [redacted] for the majority of this past week, so I apologize for my delayed response. If you are interested in discussing further next week, please feel free to let me know.

Best regards,
Terry

From: Dave, Chaitali R <[redacted]@p66.com>
Sent: Wednesday, April 24, 2019 4:00 PM
To: [redacted] Terry <[redacted]@johnzink.com>
Subject: RE: Confidential - Crude Oil Loading/Unloading Control Equipment

Sent by an external sender. Use caution opening attachments, clicking web links, or replying unless you have verified this email is legitimate.

Have you designed and implemented vapor combustion solutions for single point mooring type projects?

Regards,
Chaitali

From: [redacted] Terry <[redacted]@johnzink.com>
Sent: Tuesday, April 16, 2019 8:35 AM
To: Dave, Chaitali R <[redacted]@p66.com>
Cc: [redacted] <[redacted]@johnzink.com>
Subject: [EXTERNAL]RE: Confidential - Crude Oil Loading/Unloading Control Equipment

Chaitali –

We had some interest in the market for the ACE technology some time ago; however, it was never applied in practice. We have also fielded inquiries for single point mooring applications, but again, no company who has initially expressed interest in such an application has moved forward with a new project.

Most recently, we have seen a significant uptick in interest for vapor control solutions on offshore platforms in the Gulf of Mexico. We have performed some fairly detailed upfront engineering services for this type of application. The US market is most interested in vapor combustion solutions for this type of application.

Best regards,
Terry [redacted]

From: Dave, Chaitali R <[redacted]@p66.com>
Sent: Tuesday, April 16, 2019 7:20 AM
To: [redacted] Terry <[redacted]@johnzink.com>
Subject: RE: Confidential - Crude Oil Loading/Unloading Control Equipment

Sent by an external sender. Use caution opening attachments, clicking web links, or replying unless you have verified this email is legitimate.

Hello Terry,

I am interested in seeing what the history of the vapor control systems is applied offshore to collect and manage vapors off loading/unloading vessels through a single point mooring system such as the ACE system which described in one of your marketing materials (slide 21). Where has this type of system been applied? How many projects/locations? What is the operating history?
Any issues with the vapor collection through a spm system and any issues with water condensing in the offshore pipelines?

Regards,

Chaitali Dave
[redacted]
Phillips 66 Company
[redacted]

From: [redacted] Terry <[redacted]@johnzink.com>
Sent: Tuesday, April 16, 2019 7:13 AM
To: Dave, Chaitali R <[redacted]@p66.com>
Cc: [redacted] <[redacted]@johnzink.com>
Subject: [EXTERNAL]RE: Confidential - Crude Oil Loading/Unloading Control Equipment

Chaitali –

Thank you for your interest in John Zink. Indeed we do manufacture vapor control systems handling vapor generated from crude oil loading operations, and in fact, we have manufactured several systems for Phillips 66 over the years in this capacity. Though our technologies may be applied offshore, the very large majority of these systems are based onshore handling vapors generated during marine vessel loading operations (mainly crude oil, refined/semi-refined products, alcohols, and other petrochemicals).

Perhaps you could give me some insight regarding your interest in our products. Are you in need of a system for a specific application? If so, I can get you in touch with an applications engineer who can guide you through this process.

Best regards,

Terry [redacted] | [redacted] Director | Vapor Control Systems
John Zink Company LLC
[redacted]